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California Energy Markets:

Pressures Have Eased, but Cost Risks Remain

December 2001
2001-009

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CALIFORNIA STATE AUDITOR

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December 20, 2001 2001-009

The Governor of California
President pro Tempore of the Senate
Speaker of the Assembly
State Capitol
Sacramento, California 95814

Dear Governor and Legislative Leaders:

As required by Assembly Bill 1 of the 2001-02 First Extraordinary Session, the Bureau of State Audits presents its audit report concerning the Department of Water Resources' (department) management of the power-purchasing program.

This report concludes that while the energy crisis has eased, there remain significant cost risks to manage. The department spent $10.7 billion from January through September 2001 purchasing power on behalf of the investor-owned utilities and has assembled a portfolio of 57 long-term power contracts, valued at $42.6 billion over a 10-year period, to cover future power purchases. However, the portfolio of contracts the department assembled in a time of crisis contains significant long-term cost risks that will need to be closely managed. For example, the portfolio leaves the department exposed to substantial market risk in high peak-demand periods if supply shortages occur and to substantial market risk with surplus contract amounts in other hours of the year. The terms and conditions of the long-term contracts are also problematic because the majority of the contracts may not ensure a reliable source of power in times of tight supply and high prices, and may not ensure that sellers follow through with the construction of proposed power plants. Instead, the contracts convey lucrative financial terms upon suppliers as a means to ensure they deliver power. Further, under most of the contracts, the department cannot terminate the contract or assess penalties even if the generators repeatedly or deliberately fail to deliver power at times when the State is in dire need of it. Finally, the department lacks the necessary infrastructure and staff to manage properly its energy purchases in the short-term market.

The Legislature and governor need to make many decisions about the State's future role in the power market. These decisions include whether the department will continue to buy energy on behalf of the investor-owned utilities, management of the market and legal risks of the long-term contracts, and other operational improvements needed to improve the department's management of the power-purchasing program.

Respectfully submitted,

Elaine M. Howle

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State Auditor

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SUMMARY

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The Department of Water Resources (department) faced an immense challenge in purchasing the net-short energy of the three investor-owned utilities. The department entered into 57 long-term contracts for power with an estimated cost of $42.6 billion over the next 10 years. Although the energy crisis has now eased, significant cost and reliability risks remain. Specifically, we determined that:

- ☑ *The speed in which the department entered into contracts in response to the crisis precluded the planning necessary for a power-purchasing program of this size. As a result, it assembled a portfolio of power contracts that presents significant risks that will need careful management to avoid increased costs to consumers.*
- ☑ *The portfolio does not contain sufficient power for peak-demand periods, thus potentially exposing consumers to high market prices if energy supply becomes limited during those periods.*

continued on next page

RESULTS IN BRIEF

The California energy crisis, which peaked between late 2000 and mid–2001, was unprecedented. Energy prices rose to all-time highs, and blackouts occurred in several instances. The wholesale energy prices were symptomatic of deeper problems, some of which—like the weather and recent high prices for natural gas—were beyond state regulatory control. For instance, abnormal weather patterns in the western region during the summer of 2000 exacerbated a long-standing energy imbalance, in which demand for electricity increased faster than the supply in California. The two largest investor-owned utilities in the State of California (State) were unable to pass the increased costs for electricity to ratepayers due to restrictions imposed by the laws that had restructured California's energy market, while a third utility was able to do so because it had met certain cost recovery criteria. However, all three utilities soon experienced credit problems and had difficulty convincing energy power generators to sell electricity to them. By late 2000, the State clearly needed to intervene.

In response to the crisis, the Legislature passed a number of bills, including Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X), which authorized the Department of Water Resources (department) to purchase the net-short energy for the three investor-owned utilities. The net short is the difference between the power that the three investor-owned utilities provide from their own supplies and the total consumer demand for power, an amount that varies considerably over the course of a day, week, month, and year. Despite the inadequate lead time to prepare for its new role as purchaser of the State's power, the department did step in and buy the power needed to keep the lights on in California. Before the enactment of AB 1X, the department's organization focused on managing the State's water system. The department managed the State Water Project's electrical power requirements through the department's own power generation and through power purchase agreements that were, for the most part, balanced with its power needs. In addition, the department purchased extra power in daily volumes of tens or hundreds of megawatts.

- ☑ *The majority of the contracts are not written to ensure a reliable source of power, but instead they convey lucrative financial terms upon the suppliers to ensure that energy is delivered. In addition, the terms of the contracts contain provisions that can increase the cost of power; thus they need careful management to avoid additional costs to the consumers.*
- ☑ *The department lacks the infrastructure needed to properly manage the purchases of the net short, but is taking steps to build up its capabilities.*
- ☑ *Many decisions need to be made about the State's future role in the power market. The department's authority to contract and purchase the net short ends after 2002, yet it or another entity will need to manage the considerable market and legal risks of the power contracts and, if the utilities are not creditworthy, purchase the net short.*
- ☑ *Operational improvements are needed to strengthen the department's administration of the power-purchasing program.*

The new power-purchasing role was an immense challenge that would have been difficult even for an organization with the needed infrastructure in place. Through September 2001 the department had spent nearly $10.7 billion to purchase energy under contract or in the spot market to meet the daily needs of the ratepayers of the three investor-owned utilities. When implementing AB 1X, the department—along with its consultants and the energy advisers appointed by the governor—undertook an effort to sign long-term contracts with power generators in an attempt to calm power prices. Subsequently, the department entered 57 long-term power contracts at a total value of approximately $42.6 billion over the next 10 years.

The portfolio of long-term contracts that the department has assembled as a response to the crisis contains cost risks that must continue to be carefully managed. Extraordinary circumstances have complicated the department's efforts: the large size and scope of the net short; the immediate need to buy the net short on the spot market at record high prices; a reliability crisis in the State's power system; and concerns about whether the department was creditworthy. Nevertheless, the department was charged with providing reliable power at the lowest possible cost, yet the portfolio of contracts emphasizes year-round energy but does not similarly emphasize delivery during peak-demand hours. The risk in the portfolio that the department must carefully manage is that the portfolio leaves it exposed to substantial market risk in high peak-demand periods if supply shortages occur and to substantial market risk with surplus contract amounts in other hours of the year. Compounding this problem is that many of the contracts are nondispatchable, meaning that the department must pay for the power whether or not it is needed. Further, based on present forecasts, from the fourth quarter of 2003 through the first quarter of 2005, the department has procured more power than consumers in Southern California need. Because facilities powered by natural gas produce most of the energy for which the department contracted, the department could also have employed more tolling agreements, which would have allowed the contract price to decrease if gas prices decrease, as is predicted. However, according to the department, before receiving an opinion from the attorney general on February 28, 2001, affirming its authority, the department was not certain that AB 1X authorized it to purchase the natural gas supplies required under tolling agreements.

The department is considering various mitigation strategies for these risks and the extent to which the strategies will be successful is unknown at this time. For example, the department presently expects to fill energy needs in peak-demand periods with market purchases rather than more contract purchases. The premise behind this approach—adequate supply availability and low prices during peak periods—may in fact occur and the strategy may be successful. However, it is also possible that the suppliers not under contract will choose to not make supply available, at least not for low prices. Also, the department hopes to exchange some of its excess power in low demand periods in California with the entities in the Pacific Northwest in exchange for power in peak-demand periods in California, since the energy needs of the two regions complement each other. Due to the length of some of the long-term contracts, 10 or more years, and the uncertainty over what entity will be managing the net short, it is also important to note that whoever manages the net short could choose to put more of the peak-demand period needs under short- or long-term contracts if that entity assesses its risk for these periods differently than the department presently does.

The department's rush to obtain contracts quickly—it entered about 40 agreements with a value of $35.9 billion in just 30 days—may have played a role in the composition of the portfolio because the department's rush precluded the planning and analysis that are necessary for developing a portfolio of this magnitude. Given the urgency to gain control of power prices and the pace that it chose in reacting to the crisis, the department had little opportunity to conduct the planning that was needed. The choice to move quickly was one of the options that the department could have taken. However, going slower may have resulted in a portfolio with fewer, or less extensive, cost risks to manage.

Most of the contracts that the department has entered with power generators do not include the terms and conditions that one would expect to see in agreements that ensure the reliable supply of energy. A key goal of AB 1X is for the department to obtain a portfolio of power contracts to supply a reliable source of power at the lowest possible cost so that the State could address the unprecedented financial and supply emergency in its electricity markets. When measuring the adequacy of the terms and conditions of the contracts, we tested them against the conditions that prompted the State to engage in purchasing electricity. In other words, we analyzed whether the contracts assure reliable delivery of power in times of high prices and tight supply.

Our detailed review of 19 transactions, constituting 61 percent of the total gigawatt-hours purchased, and a screening of others concluded that most of the power supplies fall under contracts with terms and conditions that may not assure that reliable sources of power will be available to the department. For example, under the terms of most of the contracts, the department cannot terminate the contract or assess penalties even if generators repeatedly or intentionally fail to deliver power at times when the State urgently needs power. Instead, the department can only recover the difference between the contract price and the cost of the replacement power. The department needed these contracts to include a remedy like the right to terminate the agreements when generators repeatedly fail to deliver so that the department has the leverage to compel generators to deliver power in times of severe need or to replace generators with other, more reliable generators.

The department's contracts also often lack terms and conditions that would better ensure other reliability goals of the contracting effort, including terms that would better ensure that generators are making appropriate progress on building the facilities that will supply the power for which the department has contracted and allowing the department to inspect facilities that the generators say are unable to produce power because of mechanical difficulties. Moreover, the contracts may not always ensure that when the State pays a premium for construction of new generating facilities, the new construction occurs and the generators actually make available and deliver the power produced by the new facilities.

Although the department was in a weak bargaining position because of the financial crisis in the electricity markets, its rush to ease the electricity crisis by locking in power supply through long-term contracts weakened its position even further. In its request for bids, the department did not request contract terms and conditions that are standard in the power industry for entities that must ensure reliable delivery of power. We found that in later contracts sellers agreed to terms and conditions that better assure reliable power delivery. Because the department apparently did not ask for certain reliability terms recognized by the power industry until after it had made the bulk of the deals, we cannot determine whether the department would have been able to obtain more favorable reliability terms in the earlier long-term contracts. We did note that while the terms and conditions improved in the long-term contracts negotiated after March 2001, the department negotiated the vast majority of the power, costing

$35.9 billion, before March 2, 2001, during the period in which we found that the terms and conditions regarding reliability of power delivery were least favorable to the State.

The contract costs are not fixed and could rise substantially if the department does not manage its legal risk in anticipation of exposure to potential liabilities and to defaults by energy sellers. For example, the department needs to guard against potential events of default that could expose the State to huge early termination payments. Also, the department needs to protect itself from generator costs that the contracts have shifted to the department. Such costs could include governmental charges, environmental compliance fees, scheduling imbalance penalties, and gas imbalance charges.

Once the department became responsible for the net short, it began purchasing up to 200,000 megawatts of electricity each day. From January 2001 through August 2001, the department spent more than $8 billion on transactions for short-term power agreements. Because California lacked creditworthy buyers, the department became the market, purchasing most of the State's power.

Various factors hampered the department's efforts in its new role. Specifically, the department initially had to purchase much of this power each day in a dysfunctional market from market-savvy sellers. The department's challenge became especially difficult because it lacked the infrastructure and the experienced, skilled staff needed to perform at this level. Consequently, at the same time that the department struggled with purchasing needed power, it also struggled to establish the organization it would need to meet the challenge.

The department has not yet implemented the infrastructure and hired the staff required to meet its continuing challenges. For example, the department is still developing systems for working with the investor-owned utilities to forecast demand, schedule the least-cost available power, and manage the delivery risks. In addition, the department still needs to resolve settlement process problems associated with the energy and ancillary services functions that the department has been conducting and continues to conduct on behalf of the California Independent System Operator (ISO). This resolution is important because under a recent Federal Energy Regulatory Commission (FERC) order, the failure of the department and the ISO to reach agreement on how

to facilitate the payment of long-outstanding power obligations may disrupt the future supply of available power in the ISO's short-term markets.

The governor, the Legislature, and the department need to make many decisions about the future role of the State in the power market. To a large extent, the problems we identified in the department's implementation of the power program arose because the department was given this mission in the midst of the power crisis with too little time to plan and prepare adequately. Now that the crisis has eased, the Legislature and the governor should consider how best to serve the power requirements of the State's consumers over the long term and how best to manage the costs and mitigate the risks of the power contracts. This analysis should result in a comprehensive strategic plan that considers both whether the department should continue to administer all aspects of the power-purchasing program as well as a specific set of plans on how to improve the current operations. The plan is necessary regardless of whether the department continues to manage the program or whether the program becomes a separate state agency or a different type of governmental entity.

The Legislature will also need to evaluate whether to extend the department's responsibilities beyond January 1, 2003, to allow time for present uncertainties that affect these decisions—such as the financial health of the investor-owned utilities and the role of the new state power authority—to be resolved. Other relevant factors that decision makers must consider include the fact that current long-term contracts do not permit the State to renegotiate or quit contracts that become burdensome or unfavorable, such as when the contracted power is no longer needed or costs are significantly greater than market prices. In addition, although the department can assign contracts to other governmental entities, assignment to utilities generally requires the sellers' consent. Further, the Legislature needs to take into account that the administering entity must have the ability to carry out the full functions of a power program of this scale. For example, the department needs advisers experienced in protecting the interests of power programs before regulatory bodies to minimize its regulatory risks. Even though the California Public Utilities Commission (CPUC) and FERC do not directly regulate the department, the actions of those commissions have substantial bearing on the market within which the department operates. In addition, the department still needs authority to enter financial transactions to manage gas and electric transaction risks.

The department's responsibilities remain substantial, not the least of which is its current management of a $42.6 billion contract portfolio focused on minimizing legal and cost risks to ratepayers. The department needs to make significant efforts to improve its internal capabilities and operations so that it can effectively administer the power-purchasing program.

RECOMMENDATIONS

To plan and manage the economic aspects of its portfolio effectively, the department should do the following:

- Conduct within 90 days an in-depth economic assessment of its contracts and the overall supply portfolio that serves customers of the investor-owned utilities. This assessment should occur in conjunction with the legal review noted below to assure that the department can develop an effective overall strategy for contract management. In addition, the assessment should focus on how the contracts fit into the overall portfolio and on the costs relative to current expectations of market conditions.

- Develop a contract renegotiation strategy, informed by legal and economic reviews, that centers on improving the reliability and the overall balance and performance of the portfolio.

To anticipate and manage its legal risk, the department should undertake these actions:

- Perform within 90 days an in-depth assessment of its legal risk and legal services requirements to ensure that the department can develop an effective strategy for legal management.

- Establish an ongoing legal services function that specializes in power contract management, negotiation, and litigation to make certain that the department's legal assessment and representation is on par with those of the other parties participating in the contracts. When necessary to avoid conflicts, this legal function should be distinct from counsel retained to sell bonds or provide legal advice to the State Water Project.

- Investigate all audit and other rights available to the department under its contracts to assure that it can develop a proper program for performance enforcement.

To further develop its operations for entering short-term agreements for power supplies, the department should take these steps:

- Collaborate with market participants to resolve settlement process problems associated with the energy and ancillary services functions that the department conducts on behalf of the ISO.

- Coordinate with the investor-owned utilities and the CPUC to ensure that the rate incentives associated with utility-retained generation scheduling are resolved to support the dispatch of the lowest cost energy.

The Legislature should consider developing an appropriate statutory framework, including the possible amendment of AB 1X, to extend the department's purchasing authority to allow adequate time for implementing the strategic framework and to assure continuity of the purchasing function and an effective transition of this function, presumably to the investor-owned utilities.

Additionally, the department should develop a strategic plan for the future of the power-purchasing program at the department, and this plan should include the assessment of the necessary transition processes needed to allow orderly transfer of functions to the ISO, the investor-owned utilities, and others, as appropriate.

To improve its ability to carry out the full functions of a power program of this scale, the department should do the following:

- In its future efforts to protect the interests of the power-purchasing program, the department should retain independent legal counsel to advise the department on matters pertaining to state and federal regulatory issues that affect the power-purchasing program when those interests conflict with the interests of the State Water Project.

- Seek clear statutory authority to use financial instruments to manage gas and electric transaction risks.

AGENCY COMMENTS

The department believes that our report fails in its primary purpose because it does not address the impact of the department's decisions in stabilizing prices and restoring system reliability. It also believes the report uses the wrong standard of evaluation because it believes the report does not evaluate the reasonableness of the department's decisions within the context of the crisis environment that they were made, the information that was available to the department at the time, and against the tremendous risks to the State's economy, and health and safety of its citizens in failing to take decisive action. Notwithstanding its concerns regarding the focus of the report, the department states that it has already moved forward on implementing many of the recommendations in the audit report.

Contrary to the department's assertion, we fulfilled our mandate and focused our analysis on the department's implementation of the power-purchasing program. We did not perceive our mission as trying to identify how much credit should be attributed to a variety of events that contributed to the improved price stability and system reliability in the spring and summer of 2001. Rather, we focused on the potential risks in the portfolio of contracts that the department developed in a time of crisis, which we fully describe, and on how the State should best manage those risks and plan for the future of the power-purchasing program. Our comments to the department's response begin on page 247. ■

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INTRODUCTION

BACKGROUND

When the governor signed into law Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X) in February 2001, the California Department of Water Resources (department) became responsible for buying power on behalf of the State's investor-owned utilities. The law created the Purchase and Sale of Electric Power Program (power-purchasing program) and gave the department its new role in the midst of an unprecedented financial and reliability crisis in the State's electricity industry. Primarily affected by the power-purchasing program are the retail customers of the State's three investor-owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Supplying electricity to approximately 77 percent of electrical power consumers in the State, these utilities serve the State's coastal areas from Eureka to the Mexican border and most of California's inland areas.

Through September 2001 the department had spent nearly $10.7 billion, purchasing nearly 30 percent of the electricity consumed in the State. The department has collected about $2.3 billion from the sale of this power. In addition, it has completed 57 long-term power contracts for power to be delivered over the next 10 years at an estimated cost of $42.6 billion. These contracts represent approximately 32 percent of the energy requirements for the investor-owned utilities over the next 10 years, according to computations by the department's consultant. In buying that power and executing those contracts, the department has incurred administrative and general expenses of approximately $29 million through September 2001.

UNDERLYING PROBLEMS WITH CALIFORNIA'S ELECTRICITY SUPPLY REACHED CRISIS LEVELS IN FISCAL YEAR 2000–01

Following the lead of the federal government and the California Public Utilities Commission (CPUC), the Legislature deregulated California's electrical industry in 1996 when it

passed Assembly Bill 1890 of the 1995–96 Regular Session. This law made many changes to the structure and operation of the power markets in California.

The State's ongoing energy problems converged in the summer of 2000, causing wholesale electricity prices in the spot markets—commodity markets that sell electricity—to reach very high levels. The wholesale energy prices were symptomatic of deeper problems, some of which—like the weather and recent high prices for natural gas—were beyond state regulatory control. For instance, abnormal weather patterns in the western region during the summer of 2000 exacerbated a long-standing energy imbalance, in which demand for electricity increased faster than the supply in California. Moreover, both the legislated terms of deregulation and the way in which the State implemented deregulation added to California's power woes. For example, the implementation of deregulation initially required the investor-owned utilities to sell and purchase on the volatile spot market all of the electricity they needed to serve their customers. At the same time, the two largest investor-owned utilities were unable to pass on much of these higher wholesale costs to their customers because of the legislated freeze on retail rates. As a result, by December 2000, both PG&E and SCE had amassed huge debts and teetered on the verge of bankruptcy. SDG&E was allowed to recover wholesale price increases through higher retail rates, but these higher rates burdened its customers.

During 2000 the problems in California's electricity markets became a crisis. The shortage of power in the California energy markets resulted in a number of blackouts. On a June day when temperatures in San Francisco reached 103 degrees, a series of localized, rolling blackouts affected almost 100,000 customers of PG&E. On December 7, 2000, the independent agency responsible for operating the State's transmission system for delivering power to consumers, the California Independent System Operator (ISO) issued its first stage 3 warning. These warnings occur when the anticipated available power will not comfortably meet consumers' demand and when any further unfavorable changes in the balance of supply and demand could result in widespread power outages.

With the new year, credit quality issues became critical for PG&E and SCE and, ultimately, for the market and the State. By January 2001 both PG&E and SCE began defaulting on power bills. The financial position of SDG&E remained relatively sound because it had been allowed to recover its escalating costs, but customers of SDG&E saw their utility bills more than double as

the utility passed these costs along. With the deteriorating financial condition of the investor-owned utilities, California's electrical power market lacked a creditworthy entity to purchase the power needed each day in the State.

THE CALIFORNIA LEGISLATURE RESPONDED TO THE CRISIS

Recognizing that California was facing potentially serious electricity shortages that called for immediate action, the Legislature crafted a number of bills aimed at quickly increasing the energy supply and reducing demand. For example, as early as August 2000, the Legislature passed Assembly Bill 970, the California Energy Security and Reliability Act of 2000. This legislation mandates that the California Energy Commission (energy commission) and the CPUC hasten to bring new power plants on-line, address limitations in the electrical transmission and distribution system, and make significant new investments in conservation. However, the primary purpose behind the legislation was to reduce demand during peak hours by the time summer 2001 arrived. AB 970 requires the energy commission and the CPUC to implement demand reduction programs, including ones offering incentives to electricity customers who take specific steps to conserve and ones that encourage customers to reduce demand for electricity during peak periods.

In December 2000 and continuing through mid-January 2001, it became increasingly apparent that the investor-owned utilities were not perceived as creditworthy buyers and that some mechanism was needed to assure electricity sellers that the purchasers of California's power were creditworthy. The department participated in a small way in December 2000 by purchasing energy on behalf of the ISO when the suppliers were unwilling to extend credit to the ISO. The department operates the State Water Project (water project), which has had some experience in managing its 2,400 megawatt need for power and had some limited experience with long-term contracts, principally before deregulation.

On January 17, 2001, the governor proclaimed a state of emergency, citing the imminent threat of widespread, prolonged disruption of electrical power caused by supply shortages and rising prices. According to the governor, these conditions imperiled the safety of the people and property within the State.

After the governor's emergency declaration on January 17, 2001, the department became the purchaser of the *net short,* which is the difference between the power that the three utilities provide from their own supplies and the total consumer demand for power at any given time. Essentially assuming the purchasing role of the investor-owned utilities, the department set out to meet the challenge. The department also became involved in planning a program that would require it to take the lead in addressing the crisis and that would include plans for entering long-term contracts.

On January 24, the governor appointed the general manager of the Los Angeles Department of Water and Power "as adviser to the California Department of Water Resources" and he served as lead negotiator for the long-term contracts. As the department was busy working on proposals for a program that would enable it to fill the role that the investor-owned utilities could no longer play, the Legislature was working rapidly to craft the legislation that would give the department the necessary statutory authority to assume that role.

For example, Senate Bill 7 of the 2001–02 First Extraordinary Session was signed into law on January 19, 2001, and it authorized the department to purchase electrical power from any party and to make that power available at cost to the ISO, public utility corporations, or retail customers for not more than 12 days from the bill's effective date. That authority lapsed on February 2, 2001. The bill also transferred $400 million from the State's General Fund to the department for implementing the bill.

The passage of AB 1X was just one of the steps that the Legislature took to aid the State during the electrical power crisis and to cope with the inability of PG&E and SCE to buy power for their customers. This legislation authorizes the department to purchase the power necessary to meet the energy requirements of the investor-owned utilities, including SDG&E, and to sell the power to retail customers within the State. Under the legislation, the department purchases the net short or the amount of power needed by retail customers that the investor-owned utilities do not provide through their generation or through contracts for power purchases. The department, based on data provided by the investor-owned utilities and the ISO, covers the net short through a combination of long- and short-term contracts, purchase commitments made a day ahead and an hour ahead of the estimated demand of retail customers, and real-time purchases to match supply to actual demand and to maintain

adequate reserve capacity. At the wholesale level, electrical power is typically traded in units known as *megawatts* or in *megawatt-hours*. A megawatt equals 1 million watts of power and is equivalent to the amount of power needed to light ten thousand 100-watt lightbulbs. A megawatt-hour is the amount of power needed to light those ten thousand lightbulbs for one hour.

The declared intent of AB 1X is to build a portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour. The intended benefit of these contracts is to stabilize the electrical power market and provide the State with a reliable source of energy for the future. The broad objectives and latitude assigned to the department were important features given the unprecedented crisis that existed in the California electricity markets at that time. After assessing the need for electrical power, the department had the discretion to determine the necessary or appropriate contractual terms for the price of the energy it purchased as well as the duration of the agreements. However, the department's authority to contract for the purchase of electrical power under AB 1X terminates on January 1, 2003, although it may subsequently administer contracts entered into before that date and may also sell electricity.

Factors From AB 1X That the Department Is to Consider When Building a Portfolio of Power Contracts

- The intent of the program to provide reliable service at the lowest possible price per kilowatt-hour.
- Each aspect of the overall load profile.
- The desire to secure as much low-cost power as possible under contract.
- The duration and timing of contracts made available from sellers.
- The length of time sellers of electricity offer to sell electricity.
- The desire to secure as much firm and nonfirm renewable energy as possible.

In addition to giving the department the authority to purchase and sell electrical power, AB 1X allows the department to enter into servicing agreements with the investor-owned utilities to provide for the delivery of power to retail customers and the necessary billing and collection activities associated with the sales.

Finally, AB 1X furnishes a financing mechanism for the power purchase program. The law authorizes the department to recover the costs of providing needed energy, including the costs of issuing and repaying revenue bonds and other debt, through charges to ratepayers of SCE, PG&E, and SDG&E. An amendment to AB 1X authorizes the department to issue up to $13.4 billion in bonds to pay the costs of the power-purchasing program. These bonds will be the exclusive obligation of the department's electric power fund and will be repaid by revenues from the sale of electrical power. Under AB 1X, the department presents to the CPUC the

amount of revenue it requires from ratepayers so that the CPUC can order the investor-owned utilities to collect associated charges from retail customers and remit these fees to the department.

As part of a longer-term solution to the energy crisis, Senate Bill 6X became law and created the California Consumer Power and Conservation Financing Authority (power authority). The power authority's role is to meet the State's needs to finance, purchase, lease, own, operate, acquire, or otherwise provide financial assistance for public and private facilities for the generation and transmission of electricity and for renewable energy, energy efficiency, and conservation programs. With its ability to issue up to $5 billion in revenue bond indebtedness, the power authority reportedly will be looking at various options to meet its charge. For example, the power authority indicates that if it owned several thousand megawatts of electrical resources that the State could use for reserves, then these services would be available for half the current cost instead of for whatever cost the market will bear.

THE MISSION OF ASSEMBLY BILL 1X DWARFED THE DEPARTMENT'S CAPABILITIES

The State's new power-buying responsibilities under AB 1X immediately and substantially transformed the department's power procurement operations. The organization behind the department's water project had experience with electricity trading and scheduling but on a much smaller scale than what the State needed for the power-purchasing program.

Before the energy crisis, the main function of the water project organization was to manage the State's water system. Acquisition of electricity was a significant part of this system, but it was not the organization's primary business. When the department began purchasing power for the investor-owned utilities, the magnitude of its power purchasing responsibility immediately increased fivefold with the addition of more than 11,000 megawatts to its usual 2,400 megawatt load. The average daily purchases of electrical energy increased from between 10,000 and 30,000 megawatt-hours to 200,000 by February with the potential that in the summer the purchases would be up to 400,000 megawatt-hours. In the first week after the governor's January 17, 2001, declaration of a state of emergency, the department purchased more than $180 million of electrical energy, eclipsing in one week its power spending for the entire

1999–2000 fiscal year, which had come to $125 million. In February 2001, the department's spending on power under AB 1X averaged $50 million per day and approached $1.5 billion for the month. During the week of February 11, 2001, the department purchased 13.5 times as much power for its AB 1X responsibility as it did for the needs of the water project. In addition to purchasing the necessary power for the investor-owned utilities, although not a statutory responsibility, the department began making power purchases needed to assist the ISO in balancing demand with supply in the State's power delivery system.

The department entered the power business with a procurement challenge that was, in a word, extraordinary. However, it lacked the staff and resources necessary to meet this challenge. The department began this operation with significantly fewer staff members than comparable utilities employ. Moreover, the organizational challenges for the department were greater than the increase in its scale of operation would imply. The new load responsibility came in the middle of a market crisis. Virtually none of the load was covered by long-term contracts. Thus, simply to keep the lights on in the State, the department had an immediate need to engage in the spot and short-term markets for virtually all of the new load. Simultaneously, the department urgently needed to secure contracts to develop a supply portfolio that depended substantially less on the short-term markets than it did during the current crisis.

To implement AB 1X, the department initially assembled an emergency operations center at the water project's operations center. The department later created a separate division called the California Energy Resources Scheduling Division and identified 88 positions needed to perform trading, scheduling, settlements of purchases, contract negotiations and management, market analysis, and fiscal and other administrative functions. AB 1X authorized the department to contract for assistance from consultants. The department hired various energy, financial, and legal consultants.

THE DEPARTMENT HAS EXPERIENCED DELAYS IN RECOVERING THE BILLIONS SPENT ON POWER PURCHASES

Known as the *revenue requirement,* the department's mechanism for recovering the costs of operating the power-purchasing program has yet to be formally implemented. The revenue requirement is the amount that the department determines is

sufficient, along with the funds in the electric power fund, to pay bond costs, to pay for power purchased, to fund necessary or desirable reserves, to repay advances from the General Fund for power purchases including interest, and to pay the department's administrative costs for this program. The department has also decided to include in the revenue requirement the costs related to electrical conservation activities for 2001 only and the cost of electricity associated with ISO grid reliability purchases. The law provides for no outside review of the revenue requirement; instead, the law allows the department to determine just and reasonable costs.

Under AB 1X, the department is to determine the revenue requirement at least annually and is to recover it through the electricity rates that the CPUC establishes. The department is to notify the CPUC of the revenue requirement so that it can incorporate the requirement into the electricity rates paid by the ratepayers of the three investor-owned utilities. Then, before it can be assured that all of its actual prior costs and projected future costs will be included in future utility rates, the department believes that it needs to enter into a rate agreement with the CPUC regarding the procedures to be followed to determine the amounts to charge ratepayers. The department views this rate agreement as a crucial step in assuring recovery of all its future costs.

Once a rate agreement has been reached, the department expects to issue bonds to recover more than $6 billion advanced from the General Fund and to pay off a short-term loan of $4.3 billion that was issued to help fund power purchases. As spelled out in the rate agreement, revenues collected from ratepayers of the three investor-owned utilities would repay these bonds. The department had anticipated issuing the bonds prior to June 30, 2001, and when that deadline was missed, the department expected a September or October of 2001 issuance. However, delays in implementing the rate agreement have postponed the issuance of bonds until sometime in 2002. Consequently, it is uncertain when the General Fund will be reimbursed for its advances. In addition, the delay forced the department to convert its short-term loan of $4.3 billion to a three-year term loan, which the department indicates will increase the financing costs included in the revenue requirement by about $800 million.

The rate agreement has been delayed because the CPUC is unwilling to approve it. One reason for the CPUC's refusal to approve the rate agreement involves concerns as to whether the

costs and terms in the long-term power purchase contracts are in the best interest of the public. Further, the CPUC is concerned about a lack of oversight of costs since the department can pass through all costs it deems just and reasonable. In addition, the revenue requirement is currently the subject of a legal action filed in Sacramento County Superior Court by PG&E. This legal action contests the validity of the revenue requirement because it was prepared without public comment. Several consumer groups have expressed similar concerns over the revenue requirement.

In November 2001 the department revised the revenue requirement. According to the department, the revenue requirement was revised primarily to reflect changes resulting from reduced demand due to the direct access program and increased financing costs as a result of the inability to issue bonds. The current version reflects lower power costs but higher financing costs because the department has used interim financing rather than bond financing. The department notes that it changed the financing requirements principally because it and the CPUC could not agree on its proposed rate agreement. In addition, the department discontinued the funding of conservation activities through the revenue requirement. Costs for these activities had previously totaled $864 million. It did so because the CPUC indicated that it did not believe that conservation activities were allowable under AB 1X.

SCOPE AND METHODOLOGY

The California Water Code, Section 80270, requires the Bureau of State Audits to conduct a financial and performance audit of the department's implementation of the power-purchasing program. In addition to mandating this audit report, the section requires a final report on or before March 31, 2003. To implement this broad mandate, we focused on the critical tasks necessary to implement and manage a program to purchase a sufficient and reliable supply of electric power at the lowest possible price per kilowatt-hour. To assist us in forming our conclusions related to the economic and legal issues involved, we retained the services of an energy economics firm and a law firm with a significant energy practice. The energy economics firm, LaCapra Associates, and the law firm, Pierce Atwood, performed various analyses that we requested.

First, we interviewed department employees and consultants, and reviewed relevant documents so that we could understand and evaluate the department's strategy for achieving a portfolio of long-term contracts as well as analyze its effectiveness in carrying out its obligation under AB 1X. In reviewing the department's contracting strategy, we assessed the department's efforts to forecast the State's needs for electrical power.

To evaluate how effectively the department implemented its strategy for contracting with power suppliers, we performed a legal and economic review of the contract portfolio to determine whether the contracts provide for reliable power at the lowest possible price per kilowatt-hour. To assess whether the department has established the appropriate processes to manage the delivery and price risks related to the contracts, we evaluated its efforts to identify and manage those risks. We based this evaluation on data and estimates existing at a point in time. For example, we used a confidential draft consultant's report dated July 25, 2001, to develop references to the net-short position of the investor-owned utilities, and to the fractions of the net-short position provided by long-term contracts. The draft report reflected an internally consistent analysis of the net-short position and dispatch of the department's long-term contracts at a given point in time. Since then, various changes have occurred, including the selection of competitive retail electric suppliers by a large number of customers and the fact that some agreements in principle did not materialize. Our consultants have examined the changes and believe that although some numbers would change if the department completed a comprehensive update of the data, the conclusions in our report would not be affected.

To analyze how effectively the department met the State's daily needs for electrical power, we reviewed the department's strategy and policies, its resources, its organization, the qualifications of its staff, and the trading tools it used in its real-time power trading and scheduling operations.

We performed procedures to determine whether the department has met certain operational requirements of AB 1X. For example, we reviewed servicing agreements with the investor-owned utilities covering the delivery of purchased power to retail customers as well as billing and collection activities.

The department contracts with a private public accounting firm to audit the electric power fund and its water project funds. Therefore, we generally limited our financial audit to evaluating the department's efforts to segregate properly the expenditures of the power-purchasing program from the other programs it administers. We also reviewed the administrative expenditures of the power-purchasing program to assess whether AB 1X authorizes them.

Because the revenue requirement is receiving outside scrutiny from consumer advocates, the courts, and the CPUC, we did not perform a detailed review of the revenue requirement.

In addition, we did not conduct a full prudency review in the sense of examining and evaluating all aspects of the department's operations or every single contract. Instead, we focused on significant terms of contracts that were problematic or on areas of the portfolio that appeared troublesome. We did not attempt to calculate quantitatively the negative impact of the department's decisions; in other words, we did not calculate the cost to ratepayers of particular problems in the contracts.

Because of the ongoing investigations by the Fair Political Practices Commission and the Attorney General's Office, we also did not perform a detailed analysis of conflicts of interest by specific individuals. However, we did review the department's current practice of monitoring potential reported conflicts of interest. ■

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CHAPTER 1

The Portfolio of Contracts Presents Significant Cost Risks That Will Need to Be Managed

CHAPTER SUMMARY

The portfolio that the Department of Water Resources (department) has assembled as a response to the electricity crisis contains cost risks that must continue to be carefully managed. Extraordinary circumstances have complicated the department's efforts: the large size and scope of the net short (which is the difference between the power supplied by the investor-owned utilities and the total consumer demand); the need to buy the net short on the spot market at record high prices; a reliability crisis in the State's power system; and concerns about whether the department was creditworthy. Nevertheless, the department was charged with providing reliable power at the lowest possible cost.

The department's portfolio has a cost of $42.6 billion over the next 10 years. The portfolio of contracts emphasizes year-round energy but does not similarly emphasize delivery during peak-demand hours. The risk in the portfolio that the department must carefully manage is that the portfolio leaves it exposed to substantial market risk in high peak-demand periods if supply shortages occur and to substantial market risk with surplus contract amounts in other hours of the year. Compounding this problem is that many of the contracts are nondispatchable, meaning that the department must pay for the power whether or not it is needed. Further, based on present forecasts, from the fourth quarter of 2003 through the first quarter of 2005, the department has procured more power than consumers in Southern California need.

Because facilities powered by natural gas produce most of the energy for which the department contracted, the department could also have employed more tolling agreements, which would have allowed the contract price to decrease if gas prices decrease, as is predicted. However, according to the department, before receiving an opinion from the attorney general on February 28, 2001, affirming its authority, the department was not certain that Assembly Bill (AB 1X) authorized it to purchase the natural gas supplies required under tolling agreements.

The department is considering various mitigation strategies for these risks. These strategies include filling energy needs during peak periods with market purchases because it believes that adequate supply and low prices will exist in the future and exchanging excess power with entities in the Pacific Northwest. The extent to which the department's strategies will be successful is unknown at this time. Due to the length of the time period, 10 years, and the uncertainty over what entity will be managing the net short, it is also important to note that whoever manages the net short could choose to put more of the peak-demand period needs under short- or long-term contracts if that entity assesses its risk for these periods differently than the department presently does.

The department's rush to obtain contracts quickly—it entered about 40 agreements with a value of $35.9 billion in just 30 days—may have played a role in the composition of the portfolio because it precluded the planning and analysis that are necessary for developing a portfolio of this magnitude. Given the urgency to gain control of power prices and the pace that it chose in reacting to the crisis, the department had little opportunity to conduct the planning that was needed. The choice to move quickly was one of the options that the department could have taken. However, going slower may have resulted in a portfolio with fewer, or less extensive, cost risks to manage.

THE DEPARTMENT INHERITED AN IMPORTANT PORTFOLIO DESIGN CHALLENGE

In granting the department broad authority to enter contracts for power supplies, AB 1X calls for the department's Purchase and Sale of Electric Power Program (power-purchasing program) to take into account all of the following:

(a) The intent to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour.

(b) The need to have contract supplies to fit each aspect of the overall energy load profile.

(c) The desire to secure as much low-cost power as possible under contract.

(d) The duration and timing of contracts made available from sellers.

(e) The length of time sellers of electricity offer to sell such electricity.

(f) The desire to secure as much firm and nonfirm renewable energy as possible.

These features, taken together, provide broad direction to the department as to the goals it should pursue. The first item, which calls for the development of a portfolio of power contracts, represents the core purpose of achieving these goals. Restoring the reliability of the State's electric supply is clearly a primary objective. Other objectives include minimizing the prices paid by consumers and the cost of the supply under contract. Indeed, one could say that the inability of the electricity market to provide reliable, reasonably priced electricity was the reason for the passage of AB 1X as an urgency statute.

In addition, the department was to consider the full range of supply options, including sources of renewable energy, which AB 1X specifically identifies. The broad contracting authority afforded the department includes the explicit authority to enter into forward contracts and provides a framework for comprehensive planning of the State's future electricity needs and purchases.

A power portfolio generally consists of various short- and long-term contracts as well as some purchases from the spot market. AB 1X does not require that all contracts be long-term, nor does it preclude purchases from the spot market, although it clearly intends that the latter types of purchases be significantly reduced.

The Department Provides the Net Short for Retail Customers of the Investor-Owned Utilities

The department inherited the responsibility of buying power for roughly one-third of the investor-owned utilities' total power requirement.

Through AB 1X, the department inherited the responsibility of buying power for roughly one-third of the investor-owned utilities' total power requirement in 2001. The power purchased by the department is a critical component of the overall portfolio of supplies that serves customers of the State's three largest investor-owned utilities—Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

The utilities' own power generation facilities and their existing long-term power contracts were normally capable of providing about 70 percent of the energy needed by their retail customers in 2001—well short of the day-to-day demand. Before the crisis, the utilities purchased the remaining power needed each day to meet the full requirements of their retail customers—the net short—in the spot and short-term markets operated by the California Power Exchange (power exchange) and the California Independent System Operator (ISO). In January 2001 the investor-owned utilities became financially unable to buy power to supply the net-short requirements and, by the end of the month, the power exchange had become insolvent as well. By virtue of its AB 1X responsibility, the department became responsible for this net-short requirement.

By virtue of its AB 1X responsibility, the department became responsible for the net-short requirement.

The department's statutory responsibilities are substantial, but it cannot unilaterally perform this mission. If it is to ensure that utility customers pay the lowest price possible for electricity, it must seek to optimize its long- and short-term purchases relative to the supplies available from the utilities' generating facilities. Thus, close coordination between the department and the investor-owned utilities is clearly necessary. In fact, AB 1X mandates an assessment of need by the department before the commencement of the power-purchasing program and in consultation with the investor-owned utilities, the California Public Utilities Commission (CPUC), and others, as the department deems appropriate.

After the passage of AB 1X, the department was and remains the only entity financially able to assure continuity of supply for the vast majority of the State's electric consumers. Although the investor-owned utilities retained the formal "obligation to serve," financial constraints made it impossible for them to purchase the power they needed. Under the terms of AB 1X, the authority to contract for power supplies—and to take on the foregoing responsibilities—remain with the department through 2002. While the department's authority to enter new contracts of any duration under AB 1X ends at the close of 2002, that legislation does provide authority for the department to continue to manage the contract portfolio after that date and to sell energy from those contracts to the utilities' retail customers. Thus, the department may have ongoing responsibilities relative to customers of the investor-owned utilities, even though those future responsibilities are not well defined currently.

Through 2002 the department must manage its purchases in concert with the utilities' portion of the overall portfolio, with the department holding the responsibility for managing risk and reliability for the portfolio. In time, if the investor-owned utilities resume their former responsibilities, the department's portfolio of contracts will, in effect, become a component of the utilities' portfolio whether or not the contracts are formally assigned to the utilities.

Extraordinary Circumstances Complicated the Portfolio Challenge

The department's responsibility came with no contracts, no supply, and no portfolio to meet the net short.

The department's responsibility for the overall power portfolio came with virtually no warning and, at best, with a very limited opportunity for advance planning. The department's new duties came at the height of an unprecedented financial and reliability crisis in the power markets. The department's charge also came with no contracts, no supply, and no portfolio to meet any portion of the load for which the department was to be responsible. Thus, a number of extraordinary circumstances made portfolio development a unique, complex challenge.

The Size and Scope of the Task Were Enormous

Overnight, the department began buying more than one-third of the investor-owned utilities' power requirements and spending sometimes more than $50 million per day on those power purchases. As we discuss in Chapter 3, the department spent over $1 billion per month for the first few months. The department's 2001 net-short obligation was originally estimated in July 2001 to be about 16,300 megawatts of peak capacity, or 39 percent of the total utility peak demand of 42,100 megawatts. In terms of the total energy consumed, the net short was estimated at almost 67,400 gigawatt-hours.

Virtually All of the Net Short Came From the Spot Market

At the outset, nearly all purchases for the net short were from the spot market. It was broadly agreed that reducing reliance on spot markets was important for normalizing the markets. In mid-December 2000, the Federal Energy Regulatory Commission (FERC), as part of its plan to remedy problems in the market, had required the investor-owned utilities to schedule 95 percent of their load prior to the real-time market or suffer a financial penalty, thus reducing the utilities reliance on spot markets to supply the net short. However, the cash-strapped utilities had

been financially unable to pursue that objective. The FERC portfolio requirement and purchasing authority established by AB 1X put the department in a position to reduce the spot market component of the overall portfolio by entering into forward contracts, or contracts to buy electricity that would be delivered at some point in the future.

The State's Power System Underwent a Reliability Crisis

The State's power system experienced daily crises. Rolling blackouts had occurred in January 2001, and according to the ISO, it had issued stage 3 emergencies—advisories indicating that rolling blackouts are possible—almost daily throughout the month. PG&E customers who had agreed to accept power interruptions during a shortage in exchange for lower power prices had, in January 2001 alone, reached their annual limit of hours for interruption. The reliability outlook for the summer of 2001 was bleak. The rolling blackout conditions in January had occurred at a system load level of nearly 30,000 megawatts. Summer peak loads were expected to be near 44,000 megawatts.

Market Prices Rose to Unprecedented Levels

The California power market structure was seriously flawed, and spot market prices had reached unprecedented levels. Average wholesale power costs reached 32 cents and 31 cents per kilowatt-hour in December 2000 and January 2001, respectively. These prices were approximately 10 times the market prices of just one year earlier. In late January 2001 the power exchange suspended operations, ending the operation of the day-ahead, day-of, and block-forward markets that had been central to the California market. Shortly afterwards, the power exchange filed for bankruptcy. Appendix D describes these markets further. These market problems were exacerbated by similarly unprecedented price levels in the natural gas and emissions allowances markets.

The department also faced serious creditworthiness issues precipitated by the weakening financial condition of the investor-owned utilities.

Energy Sellers Had Concerns About Whether the Department Was Creditworthy

Another aspect of the department's challenge was that it faced serious issues about whether it was creditworthy. The weakening financial condition of the investor-owned utilities precipitated the crisis leading to the enactment of AB 1X. The utilities' ability to purchase power from suppliers eroded as confidence in the utilities' ability to pay for the power declined. Suppliers, increasingly concerned about receiving payment for energy deliveries,

began refusing to sell. If suppliers did sell, they demanded higher prices and tighter terms and conditions to compensate for the added financial risk.

AB 1X was, in large part, designed to establish the department as a creditworthy buyer in the market. The core provisions of AB 1X allow the department to assure revenues to pay all power costs by establishing a process for collecting costs from consumers that it alone would determine is just and reasonable. In other words, no state regulatory approval of the department's revenue requirement would be necessary. However, the department has not sold the bonds because the CPUC has been unwilling to approve the rate agreement, which permits the department to implement the revenue requirement necessary to provide the revenue stream to repay the bonds.

Clearly, potential sellers—whether or not they themselves had concerns—would use the market's concerns about whether the department was creditworthy to seek higher prices. In addition, the concerns about payment could exacerbate the possibility of shortages, as it is likely that some sellers would withhold some power from the market for this reason alone. Problems related to the department's credit standing and the effect on the short-term market are discussed in Chapter 3.

ONE PRIMARY TEST OF SUCCESS FOR THE DEPARTMENT'S POWER PORTFOLIO IS WHETHER IT PROVIDES RELIABLE SERVICE AT THE LOWEST POSSIBLE PRICE PER KILOWATT-HOUR

In any evaluation of the department's performance, one must recognize the difficulties of building—from nothing—a supply portfolio sufficient to meet the net-short position. Given the unprecedented crisis that existed in the California electricity markets with respect to both reliability and prices—a crisis that could have been lessened or averted by a portfolio of contracts—this portfolio development challenge was quite unlike any that normally falls to utilities or power suppliers of any size. The essence of the department's challenge was that it was assigned the task of procuring supply contracts at a time when spot market and forward prices in California's electricity markets were at a historic high. Nonetheless, the measure of the department's portfolio performance derives from AB 1X: Achieve an overall portfolio resulting in reliable service at the lowest possible price per kilowatt-hour.

The essence of the department's challenge was that it was assigned the task of procuring supply contracts at a time when prices in California's electricity markets were at a historic high.

It is important to understand the magnitude of the portfolio-building task faced by the department. Under more typical circumstances, organizations build utility portfolios incrementally; in other words, they generally add resources at a pace designed to meet load growth and to replace old equipment. The department, on the other hand, had to build a portfolio immediately rather than incrementally. Its acquisitions within the first month were equivalent to the power supplied by a major United States utility.

One must also recognize that the statutory language accommodates a reasonable balancing of objectives for reliability and cost-minimization. The language does not suggest the department is to pursue increasing increments of reliability at any price. Rather, the implication is that the department should achieve a reasonable level of reliability as cost-effectively as possible. Determining the steps necessary to bring a reasonable level of reliability to California's chaotic energy market was not a straightforward task.

After taking into consideration all the portfolio design challenges that faced the department, we used the following criteria to assess its implementation of the power-purchasing program:

1. Does the program emphasize and improve reliability?

2. Does the portfolio secured by the department, when combined with the supplies retained by the investor-owned utilities, provide the lowest possible price per kilowatt-hour to the customers?

3. Did the department adequately consider a full range of available supplies, including renewables?

The standards in this case must be high. The magnitude of the financial consequences to the State and the electricity consumers in the State are sizable and long-lived. Under the power-purchasing program, the department has spent about $10.7 billion through September 2001, and it has made commitments for future purchases of approximately $42.6 billion. But however high the standards, the assessment of the department's performance must take into consideration the extraordinary circumstances prevailing at the time.

THE DEPARTMENT'S PORTFOLIO CONTAINS NUMEROUS RISKS THAT IT MUST MANAGE AND MITIGATE

The department was granted authority through AB 1X to enter into contracts to supply the net short for customers of the investor-owned utilities. The law does not specify the terms of any contracts to be pursued, so it ultimately placed a decision with the department that was of enormous import to those customers. Forward contracts establish, in advance of actual consumption, rights to receive specific amounts of electricity at specific prices and terms. In addition, forward contracts can bring benefits by securing supplies in advance at known terms, thus avoiding the risks of relying on volatile short-term market prices. Forward contracts can be short-term—for periods of a few months or long term—for periods of one or more years. In addition, these contracts can cover any type of supply and pricing arrangement.

A key decision for the department lay in deciding the degree to which it would commit to forward contracts.

A key decision for the department involved the degree to which the department would commit to forward contracts for supplies, that is, the extent to which it would rely on contracts rather than the spot market and for how long. Forward contracts with fixed prices can mitigate the risk that consumers might be exposed to increasing spot market prices (actually, any price in excess of the contract price), but they also forgo opportunities for lower prices if market prices are low. The design of a portfolio and the reliance on fixed price contracts balances the risk of future high prices in spot markets relative to the risks of being locked into purchasing predetermined contract volumes at relatively high contract prices if market prices fall.

The department developed and implemented its portfolio design and procurement strategy very quickly in late January and early February. An early document in which the department outlines its initial portfolio strategy is contained in an April 2001 report and presents certain initial portfolio objectives. The department's portfolio strategy here appears consistent with the statutory focus on ensuring reliability and securing low-cost supplies for consumers.

Further, the same April document from the department indicates that it elected to emphasize longer-term contracts as a means to secure new generation capacity for greater reliability and long-term

Excerpt: Overview of the Department Strategy and Response

- Bids received from a diverse group of suppliers—in-state and out-of-state, existing and new power plants.
- CDWR [Department of Water Resources] strategy—build a diverse portfolio of different durations. Give priority to contracts that result in construction of new power plants and offer long-term price stability. Limit 10-year contracts to entities that can provide power supplies starting in 2001.
- Issued two competitive solicitations for power supply and responded to numerous unsolicited offers.
- Several developers of future power projects targeted for operation in 2003 and beyond submitted bids for projects either recently permitted, under permit review, or yet to be proposed to the California Energy Commission for certification (providing no benefit for immediate energy supply and cost certainty).
- Most suppliers for 2001 summer season delivery tied to longer-term sales with increasing obligations to purchase in later years, generally requesting 7 to 10 years or longer.
- Longer term transactions provide for levelized prices, which are significantly lower than short-term contract prices.

Source: Summary of the Department of Water Resources' Power Purchase Contract Efforts, April 2001.

price stability. In compiling a supply base from the proposals received in response to its request for bids, the department embraced a decision to accept contract proposals spanning a 10-year period, and this decision was critical in its impact on consumers. It committed customers of the investor-owned utilities to substantial supply quantities and corresponding costs for many years to come.

The department's decision requires close examination. Clearly, its consultant saw merit in limiting the agency's forward exposure. We also observe that the department was confronted with very substantial and serious problems in the short term. At first glance, it seems appropriate for the department to maintain a focus on securing its position during 2001 and perhaps during 2002 and 2003. Thus, the department might have determined to attack its short-term problem with shorter-term contracts of less than three years, allowing supplies in later years (and beyond the years of its statutory mandate) to be addressed in due time.

In point of fact, the department's procurement decision strategy may have been justified. The pressures on the department were considerable. It faced formidable obstacles in meeting its goal of "keeping the lights on" during the coming summer. It seems clear that if the department had relatively little leverage in the market, its ability to push suppliers for more desirable contract terms might be limited. Further, it is possible that suppliers would not respond with supplies in the near term absent a willingness by the department to make long-term purchase commitments. Finally, market price projections prepared by the department's consultant at the time indicated that spot prices would remain at high levels relative to the prices in the long-term contracts.

At the time that the department was developing its portfolio strategy, it is clear that reasonable views of possible market outcomes could have encompassed an unusually wide swath.

Those anticipating one end of a range of outcomes might have suggested that California's electricity market problems, though severe, would be short-lived. Such persons might have anticipated a return to "normalcy" in a relatively short time. Others could have reasonably foreseen wholesale market prices continuing at exceptionally high levels for several years. In fact, the initial market price trajectories developed for the department's procurement processes suggested market prices substantially above contract price levels. If one had accepted the results of those initial price trajectories as illustrative of a possible price projection in the January to February 2001 time frame, he or she would have supported the department's decision to place greater emphasis on longer-term contracts.

The portfolio strategy that ultimately emerged was focused on longer-term contracts as the means by which to secure supplies needed to prevent shortages and further rate increases in the short term.

The portfolio strategy that ultimately emerged focused on longer-term contracts as the means by which to secure supplies needed to prevent shortages and further rate increases in the short term. Under the circumstances, this focus is consistent with a strategy for an entity determined to avoid a scenario that would have spelled disaster for the State. The department's strategy seemed to focus on long-term contracts as the means to substantially mitigate the impacts of continued severe market conditions.

The portfolio strategy adopted by the department had advantages and disadvantages, which likely were foreseeable. On the upside, any commitments to "new" generating units likely would enhance reliability and the adverse price implications of short supplies by helping to restore the "normal" balance between generators' supplies and consumer demands. Conversely, as presented above, committing to substantial purchase volumes at predetermined prices would minimize opportunities to take advantage of lower market prices in the future.

The department has now assembled a substantial portfolio of contracts that secures much of the estimated net-short energy for most of the next decade. The department's supply of the net short to date has come largely from the spot market and short-term forward contracts. (Chapter 3 discusses the department's efforts in this area in detail.) Over time, supplies from the department's long-term contracts will become a much larger fraction of the overall portfolio and will cover a larger share of the net short.

The Department Landed About 40 Long-Term Power Agreements in 30 Days, Nearly Fulfilling a Decade of Requirements

The initial implementation of AB 1X included an aggressive solicitation of long-term agreements for power. As we discuss further in Chapter 2, in late January 2001, the governor appointed an energy adviser to head a special negotiating team that was given the task of directing an intensive effort to solicit and negotiate these contracts.

The requests for bids issued by the contract negotiating team initially focused on bids for the delivery of firm energy from standard products for energy at fixed prices. This focus on products that were common in the market and also simple to evaluate meant that the process could move quickly. However, the team also considered noncompliant bids to ascertain these bidders' willingness to negotiate alternative arrangements to meet the State's price and product needs. According to department documents, the initial portfolio objectives were to focus on long-term contracting for 3 to 10 years at prices below then-current short-term prices.

By March 2, 2001, the governor's energy adviser reported that the team had completed 40 long-term power purchase agreements representing as much as 10,600 megawatts of power in a given year.

These contracting efforts established a substantial portfolio of long-term contracts in short order. By March 2, 2001, the energy adviser reported that the team had completed 40 long-term power purchase agreements (including some agreements in principle) representing as much as 10,600 megawatts of power in a given year and the energy adviser proclaimed these results to be "a successful effort that is by far the largest concentrated cost-effective procurement of electricity ever undertaken."

The contracts and agreements in principle in place by March 2 secured a large fraction of the net-short energy requirements for the decade. By the beginning of October 2001, the contracting effort had completed an additional 17 contracts, raising the total to 57 contracts, and 2 more were under negotiation. Within 8 months, the department had secured long-term contracts to fill the net-short energy requirement for the decade. In July the department's consultant estimated that the long-term contracts would secure about 77 percent of the forecasted net-short energy over the next decade, providing 53 percent of the 2001 requirements and 90 percent of the 2004 requirements. The balance of the net-short energy (the residual net short) is expected to be met by a combination of spot market purchases, short-term contracts, and new conservation and demand management programs.

The department's assembled portfolio of power contracts, in its peak year of 2004, exceeds 12,000 megawatts. Roughly 5,800 megawatts of this capacity is expected to be supplied from new units scheduled to come on-line before 2004. Approximately 2,700 megawatts (27 percent) of the 2004 capacity will have economic dispatch capability. In other words, the department can vary the amount of energy that it schedules under these contracts over time so as to track the changes in load, optimize the use of spot market energy, and minimize energy surpluses. Table 1 summarizes the amount of dispatchable and nondispatchable capacity under contract each year.

TABLE 1

Capacity Supplied by Long-Term Contracts (In Megawatts)

	Calendar Year					
Capacity Type	2001	2002	2003	2004	2005	2006–10
Dispatchable	696	2,882	2,737	2,737	1,512	2,350
Nondispatchable	5,520	5,156	8,281	9,290	9,140	8,093
Totals for all contracts	**6,216**	**8,038**	**11,018**	**12,027**	**10,652**	**10,443**

Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

The Department's Long-Term Contracting Did Not Deliver Significant Amounts of Power to the Market Immediately, but May Have Had an Unquantifiable Impact on Supply Reliability and Cost Exposure in the Near-Term Market

Despite the department's intensive effort to secure long-term contracts, most of the power procured to meet the net short in 2001 was supplied from spot market and short-term forward contracts. In tandem with the long-term contracting effort, the department devoted substantial effort to procuring power in the short-term markets to fill the net short from day to day, and it worked to pursue short-term contracts (up to 3 months in duration) to reduce the reliance on the spot market. Chapter 3 discusses these short-term transactions. The department indicated that through October 26, 2001, it had purchased about 84 percent of the net-short energy through short-term contracts, block-forward contracts, and the spot market. Thus, the long-term contracts did not deliver much power during this period despite the department's desire to do so. However, the department believes that while

the volume of power under contract in June, July, and August was not a significant portion of the net short, the program's strategy of contracting for power during peak hours was effective in improving supply reliability and limiting cost exposure in the near term. This is because generators that provided peak power did not shut down at night, allowing a sufficient supply of competitive off-peak energy.

The Portfolio's Inclusion of a Significant Amount of Capacity From New Units Will Likely Help Mitigate Supply Problems in the Market

New generation can help enhance supply reliability and stabilize volatile spot market prices. The department's procurement strategy emphasized the construction of new generating resources to supply some of the energy needed to meet the net short. The construction of new capacity is a positive development because it can enhance physical reliability and puts downward pressure on spot market prices.

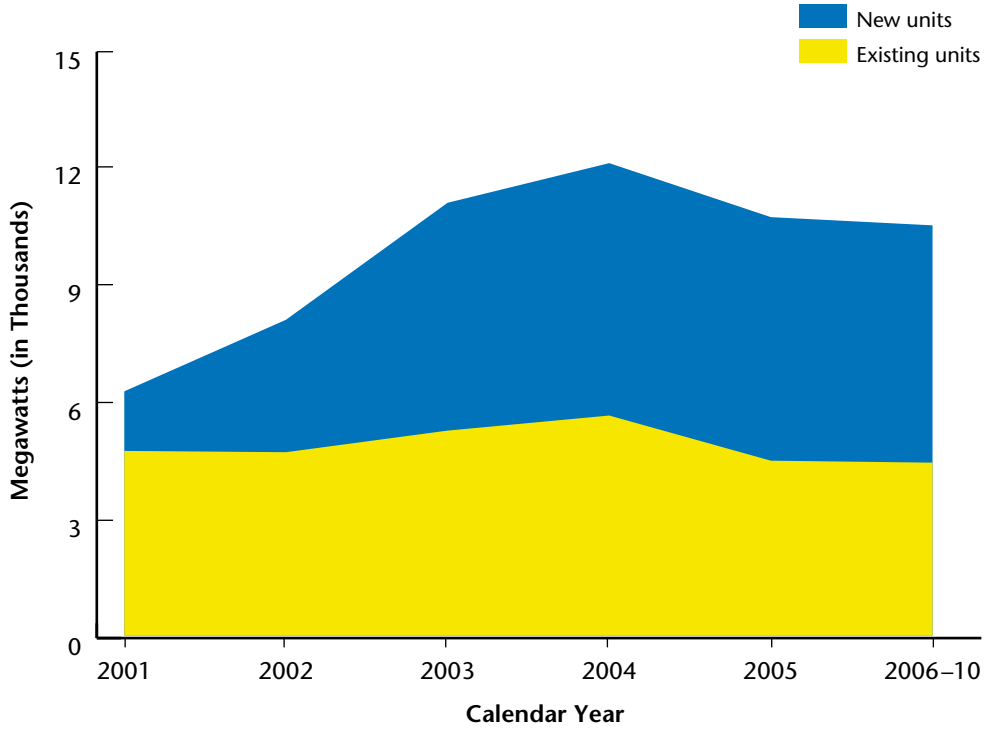
By limiting 10-year contracts to entities that could provide power in 2001, the department's strategy favored developers with projects at an advanced stage of development.

While the extent to which the department's contracting policy will cause the building of new generation capacity is not entirely clear, it is reasonable to conclude that contracts for payment of delivered power may have helped ensure completion of generation facilities. Any such result will likely be constrained by the fact that the department's procurement strategy limited 10-year contracts to entities that could provide power supplies starting in 2001. A strategy that allowed for supplies from facilities that became available in 2002 or 2003—without a requirement to deliver power from other sources in 2001—might have done more to promote development of new generation facilities. Nonetheless, the department's strategy favored developers with projects at an advanced stage of development (and, clearly, those with existing supply available) providing added certainty to those projects and increasing the likelihood that this new capacity would come into operation. While typically the imbalance between supply and demand in California may have been sufficient to boost supplies through the addition of new generating capacity, as has been the case in many other markets around the United States, due to the creditworthy problems in the California market it is unknown if market demand alone would have encouraged the development of additional generation. In any event, Figure 1 illustrates that the department's portfolio includes a significant percentage of capacity from new units, up from approximately 1,500 megawatts in 2001 to 6,400 megawatts in 2004. The assurance that this amount of new supplies will be

entering the market is important to the overall reliability and stability of the market. Chapter 2 discusses the limitations of the reliability assurances secured in the department's contracts for new supplies. These limitations may diminish the reliability benefit.

FIGURE 1

The Department of Water Resources' Contracts
New Units Versus Existing Capacity



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

The Estimated Cost of the Long-Term Contracts Is $42.6 Billion Over 10 Years

The department's portfolio comprises contracts with terms ranging from as short as a few months to as long as 20 years. In July 2001 the department's consultant estimated that the cost of the contracts over the 10-year period ending December 31, 2010, inclusive of fuel costs associated with tolling agreements, to be approximately $45.6 billion or $70 per megawatt-hour. (As Appendix A shows, our consultant estimates the cost at $42.6 billion based on slightly different data, most notably lower assumed prices for natural gas and fewer completed

contracts.) This cost estimate relates only to the long-term contracts and does not include ancillary service costs, department administrative costs, interest charges on bonds, conservation programs, and the cost of meeting the residual net short. When these costs are included, the total 10-year cost estimate increases to approximately $78.3 billion, with an average cost of $85 per megawatt-hour. Table 2 shows the distribution of the long-term contract costs over the 10-year period ending 2010.

TABLE 2

Cost of the Long-Term Contracts Over 10 Years (In Millions)

	Calendar Year						
Capacity Type	2001	2002	2003	2004	2005	2006–10	Totals Through 2010
Dispatchable	$ 154	$1,196	$1,166	$1,015	$ 497	$ 3,330	**$ 7,358**
Nondispatchable	2,291	2,682	3,784	4,243	3,924	18,277	**35,201**
Totals for all contracts	**$2,445**	**$3,878**	**$4,950**	**$5,258**	**$4,421**	**$21,607**	**$42,559**

Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

Table 3 displays the corresponding range of wholesale prices per megawatt-hour for each type of product.

TABLE 3

Average Price per Megawatt-Hour of Each Type of Product in the Long-Term Contracts*

	Calendar Year						
Product	2001	2002	2003	2004	2005	2006–10	Blended Price Through 2010
Base plus as available	$100	$ 74	$70	$64	$60	$60	**$62**
Peak	112	123	107	89	82	77	**94**
Operating reserve	—	—	—	—	—	—	—
Off-peak	149	103	95	79	—	—	**107**
Summer peak	295	119	119	64	44	69	**71**
Summer super-peak	170	147	103	82	71	67	**91**
Blended price	**$112**	**$102**	**$85**	**$71**	**$63**	**$63**	**$70**

Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

* Appendix A explains these products.

As Table 3 indicates, the prices per megawatt-hour vary considerably for the products that the department purchased. As expected, base products are generally less expensive than peaking products, primarily because base facilities cost less to operate per megawatt-hour.

The department has not provided us with an analysis to demonstrate that the actions of the contract negotiators were linked quantitatively to specific consumer objectives or to an overall supply portfolio cost objective. For instance, the department has not provided any rate or cost targets, either in terms of the impact on consumers of price per kilowatt-hour or average contract prices, that were translated into purchase parameters to guide the negotiating team. According to the department, while formal documentation in the period may be minimal due to the extraordinary circumstances, there was a specific price target. To attempt to achieve the governor's objective of no rate increases, the program identified the average cost of power produced by the investor-owned utilities from their filings with the CPUC and the goal was to match the weighted average rate of 6.9 cents per kilowatt-hour. As discussed on page 37, it achieved an average of approximately $70 per megawatt-hour (or 7 cents per kilowatt-hour.)

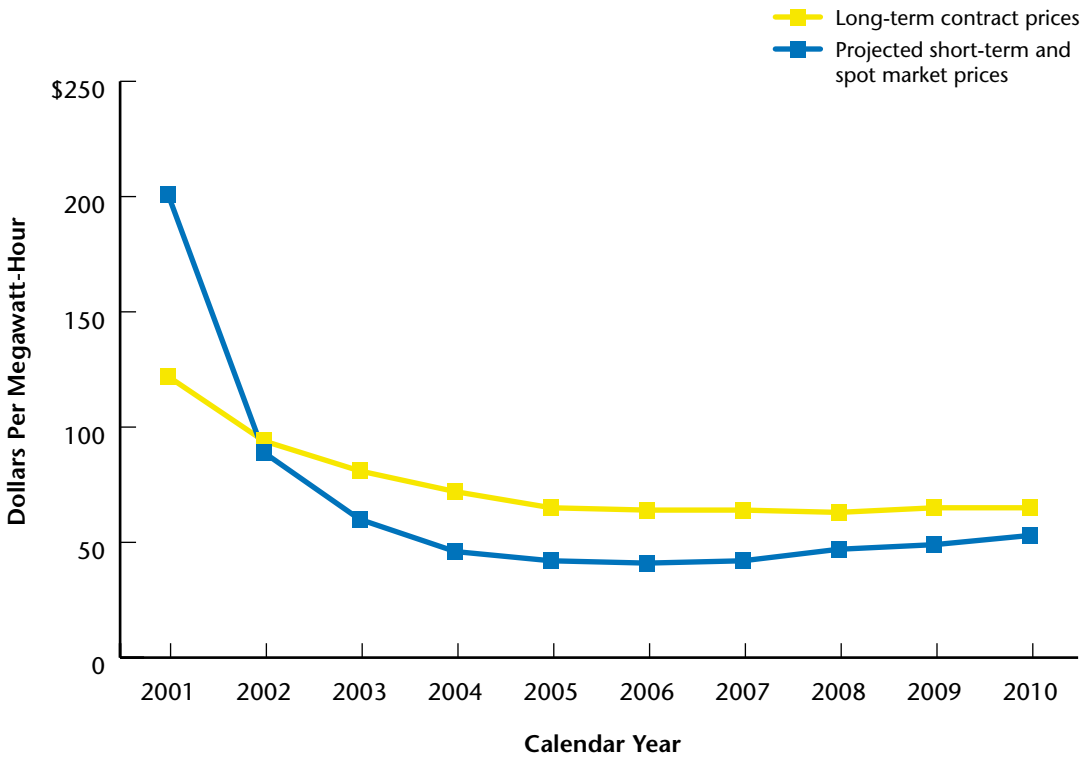
It appears that those negotiating contracts had little information that would inform their choices on contract prices or amounts that would bring the best combination of risk protection and price to consumers.

The negotiating team did have access to relatively simple market price forecasts for various electricity products but not to information that would allow it to optimize cost and performance features of the overall contract portfolio. Thus, those negotiating contracts apparently had little information that would inform their choices on contract prices or amounts that would bring the best combination of risk protection and price (or price stability) to consumers. In portfolio planning, such analysis is important because consumer prices are not determined solely by the average costs of the department's long-term contracts; rather consumer prices are based on the long-term contract costs and the costs of other supply sources needed to meet all capacity and energy requirements across a particular period. These costs include any additional spot market, short-term, and peaking capacity purchases, and the cost of the investor-owned utilities' supplies. It is possible that acquiring a greater proportion of peak contracts—which provide power for fewer hours per year—might ultimately represent the best means for minimizing overall electricity costs to consumers to the extent that these contracts would shield consumers from price spikes in spot markets during periods of peak demand. As Figure 2 on the following page shows, regardless of the average prices that will ultimately result from the department's portfolio strategy, the current result of the procurement efforts appears to

be a set of contracts that are largely priced higher than the market with respect to recent projections of market prices prepared by the department's consultant.

FIGURE 2

Projected Market Prices Are Lower Than the Department's Contract Prices (In Dollars per Megawatt-Hour)



Source: Data from Navigant Consulting, Inc., a Department of Water Resources consultant.

The Department's Long-Term Contracts Provide Ample Energy But Less Ample Capacity

This distinction between the net-short energy and net-short capacity is important. *Net-short energy* refers to the total amount of electric production required above that produced by the investor-owned utilities over a period of time, such as a year. *Net-short capacity* refers to the peak demand or maximum rate of delivery of power in any given hour above that produced by the investor-owned utilities. At all times, system operators must ensure that sufficient generating capacity is operating to meet consumer

Energy measures the amount of power produced over a period of time, whereas capacity measures the peak demand or the maximum production in a given hour.

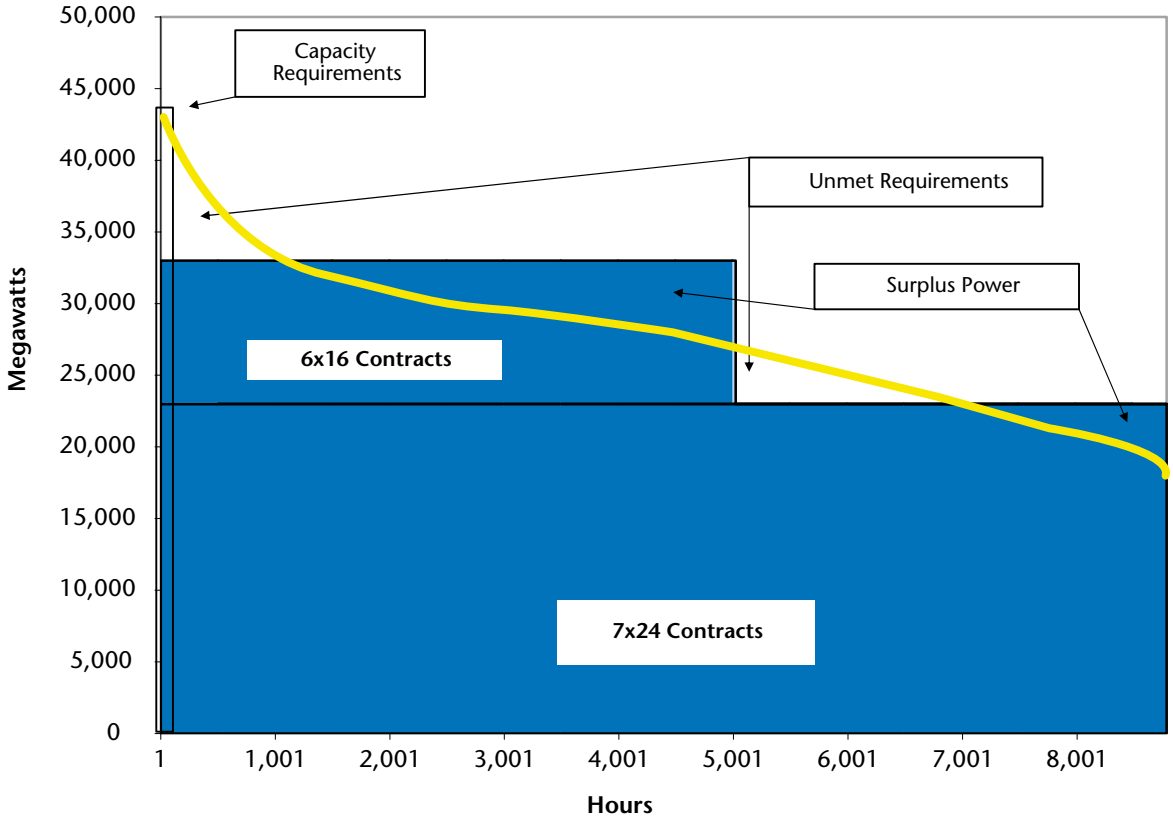
demands. Some generating units produce electricity around the clock, year-round to meet the base energy requirements of consumers. However, because consumer demands often rise above base levels—and because electricity cannot be stored—supplemental generating units are needed. There are times, such as during periods of peak demand on hot summer days, when additional generating capacity must be available to system operators to meet peak demands if blackouts and high market prices are to be avoided. Some power plants, often called "peakers," play a critical role in producing electricity during these peak-demand conditions. Peakers are idle in all but peak-demand conditions, thus typically generate very little energy.

The net-short requirement varies considerably over time, with the requirement during the hours of greatest demand being significantly higher than the average requirement. A way of measuring the variation between peak and average demand is by calculating the "load factor." The load factor is calculated by dividing the demand in gigawatt-hours for the period by the product of the peak demand and the number of hours in the period. The percentage resulting from this calculation is a measure of how efficiently facilities, that the generating capacity purchased to meet the peak demand, are used throughout the period. Generally, the higher the load factor, the more efficiently the capacity is used and the lower the cost to serve a customer or group of customers. For example, in 2001 the net-short position—for which the department is responsible—had an annual load factor of about 47 percent, meaning that the capacity acquired to meet the net-short peak demand will be fully utilized about 47 percent of the time. By comparison, the load factor for the utilities retained generation is about 65 percent. Thus the capacity used to serve the net-short position will be used less efficiently and probably at a higher cost than the capacity that the utilities retain. This is necessarily the case because most of the utilities' capacity is operating constantly to meet the base load demand.

The distinction between the load factors of these two capacities has important implications for the department in meeting its statutory obligation to contract for supplies that fit each aspect of the overall load profile so as to ensure reliable service. The utility-retained generation is predominantly baseload, around-the-clock generation because the utilities divested themselves of most of their peaking generation. By contrast, the department's position as provider of the net short carries significant peaking requirements for those hours when customer loads are high or utility generation is low.

FIGURE 3

One Year's Representative Load Distribution by Hour



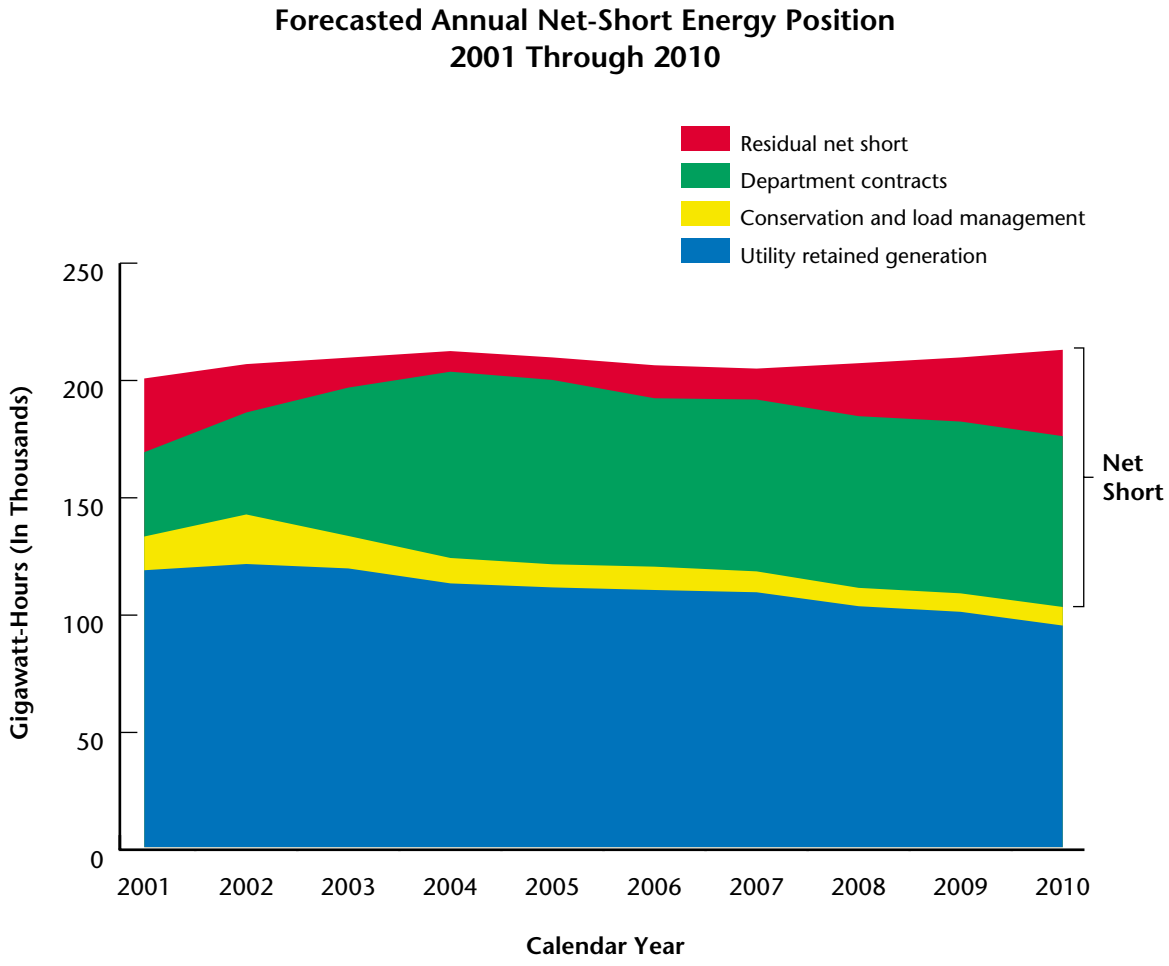
Footnotes:

The area under the line represents total electricity requirements, the shaded areas represent energy purchases, and the height of the column near hour 1 indicates the capacity requirement for the peak hour.

The purchase of 6x16 contracts involve agreements with sellers that produce energy 6 days a week, 16 hours per day. Similarly, the department has 7x24 contracts with sellers that generate energy 7 days a week, 24 hours per day.

Figure 3 illustrates the distinction between capacity and energy. The hypothetical figure shows a representative annual load profile that presents the distribution of load in each hour sorted by load level. In this example, the highest load in any hour during the year, about 44,000 megawatts, appears at hour 1 on the curve and the lowest load in any hour during the year, about 18,000 megawatts, appears at hour 8,760 on the curve. The highest load, the annual peak load of 44,000 megawatts, defines the maximum operating generation capacity needed within the year and determines the capacity requirement—the total number of megawatts the generation system must be capable of producing instantaneously to assure reliable supplies. There are

FIGURE 4



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

very few hours in the year when generation production must be at that level. The annual energy requirement is the sum of the hourly loads over all of the hours in the year and is expressed in terms of megawatt-hours.

If the department is to meet its statutory mandate to secure "contract supplies to fit each aspect of the overall energy load profile," it must plan for and obtain sufficient energy supplies to meet consumer demands over time. In particular, the department must have enough additional capacity to meet peak-demand conditions. More specifically, the department must plan for sufficient capacity to respond to normal hourly, daily, monthly, and yearly variation in loads and to generating facility outages. It also must plan for the occasional peak-load conditions during

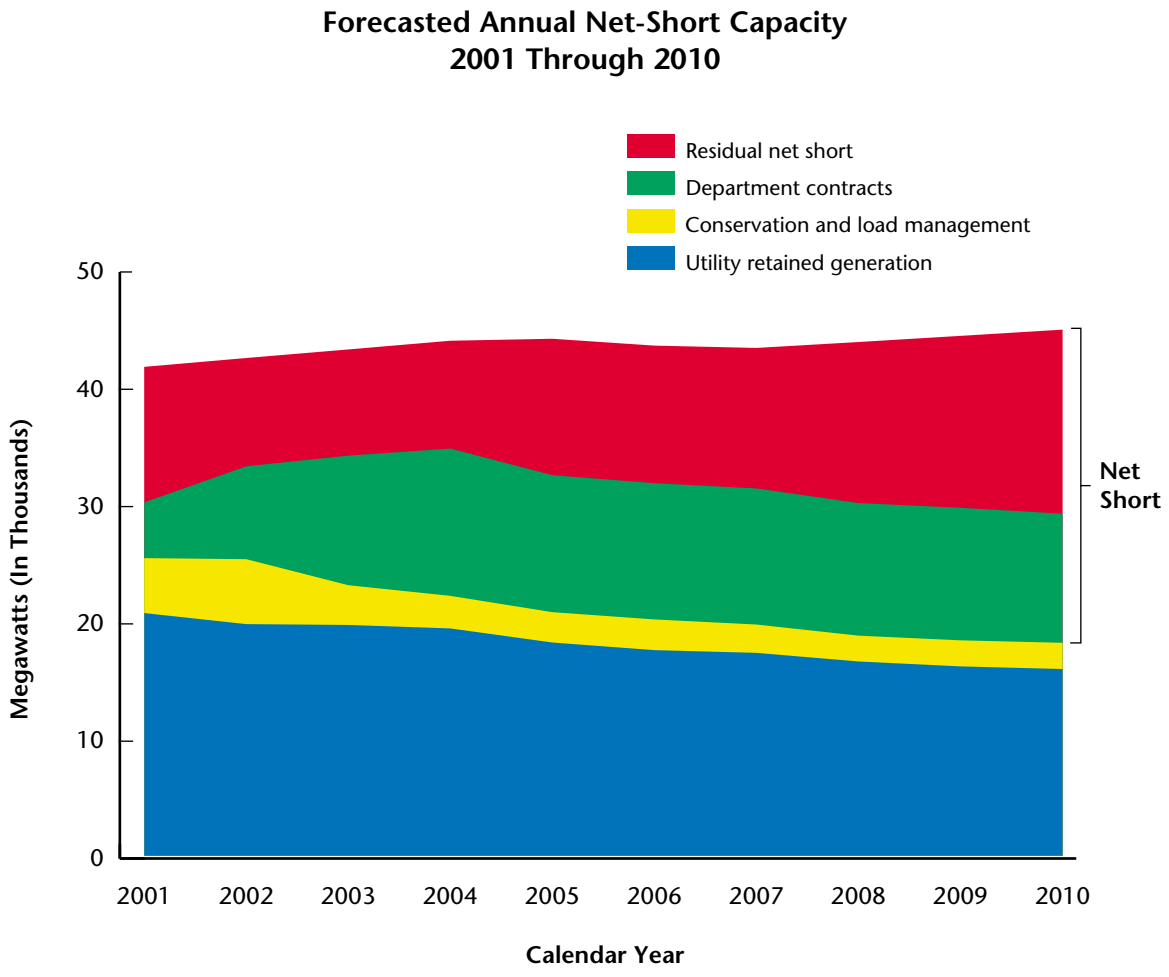
which peakers will be dispatched to preserve system reliability and spot prices will be particularly high. In short, those pursuing contracts to meet the net short must be cognizant of both energy and capacity needs.

In a July 2001 analysis, the department's consultant estimated the *net-short energy* position for all of 2001 to be approximately 67,400 gigawatt-hours, or about 34 percent of the total energy requirements of the investor-owned utilities. Further, the consultant estimated that in 2010 the net-short energy requirement will increase to about 110,000 gigawatt-hours, or about 52 percent of the utilities' total energy requirement. Figure 4 illustrates the forecasted annual net-short energy position (in gigawatt-hours per year), which is the sum of energy supplied by the department's contracts and the residual net short. The figure shows that the department now has under contract sufficient energy to meet nearly all of its projected net-short energy requirements from 2003 through the end of the decade.

A view of the department's contract activity relative to the *net-short capacity* position reveals a different picture. The department's consultant estimated that the net-short capacity position for summer 2001 would be about 16,300 megawatts, or 39 percent of the investor-owned utilities' coincident peak demand. Further, its consultant projects that the net-short capacity position will increase substantially over time to about 27,000 megawatts, or 60 percent of investor-owned utilities' peak demand, in 2010.

Figure 5 presents the department's forecasted net-short capacity position in megawatts for the period 2001 through 2010. The figure illustrates the degree to which the department's contract purchases are sufficient to respond to its net-short capacity requirements across the decade. In contrast to Figure 4, which reveals that the department has signed contracts to meet most of its net-short energy position until 2010, Figure 5 shows that the department has secured enough capacity to meet only about half of the net-short capacity position. We note that Figure 5 does not reveal the substantial variations in the net-short capacity position (that is, peak loads less capacity from the investor-owned utilities' retained generation) to which the department will have to respond over time. This variation in the net-short capacity position will result from changes in the capacity contributions from investor-owned utilities' retained generation, changes in loads with the seasons, daily and hourly changes in loads as commercial facilities initiate and close operations, as customers operate home appliances, and so forth. Thus, there will be periods

FIGURE 5



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

during which supplies currently under contract will be sufficient to respond fully to the department's capacity requirements. Nonetheless, during other periods, which cannot be predicted with precision, the current contract portfolio will not be sufficient relative to the department's needs.

The department has entered into a mix of long-term contracts with varying delivery periods. Some of the contracts require that energy be provided 24 hours a day, 7 days a week (known as a 7x24 product), 52 weeks per year (8,760 hours per year). Other contracts are for so-called peaking products that provide energy for a limited daily period and possibly for a limited number of days per week. The most common peaking product purchased by the department requires energy to be delivered 16 hours a day,

6 days a week (known as a 6x16 product), 52 weeks per year (nearly 5,000 hours per year). This type of product provides energy at times when loads are usually higher (all weekdays and Saturdays, primarily during daytime hours). The department has also purchased lesser amounts of power in other types of contracts, including off-peak, summer peak, and summer super-peak. These products provide varying amounts of power. For example, summer super-peak products require the supplier to provide energy 8 hours a day, 5 days a week during the peak summer months (about 500 hours per year).

Together, the department's contracts provide most of the net-short energy requirements during most hours of the year but much less of the net-short capacity during peak demand conditions. For example, in 2004, when overall contract deliveries will be at their maximum, the long-term contracts are projected to supply about 90 percent of the net-short energy requirements but only about 58 percent of the net-short peak demand.

Calculations by a department consultant reflect that the contracts will not cover a substantial portion of the estimated load during hot summer days, when demand for electricity is at its maximum.

The department's consultant therefore estimates that the contracts will not cover a substantial portion of the estimated load during hot summer days, when demand for electricity is at its highest. The amount of the shortage—the residual net short—on those days will be on the order of 9,200 megawatts in 2002, increasing to about 15,700 megawatts by 2010. During these peak conditions, electricity demand will be at least several thousand megawatts greater than the amount of power the department has under contract from 7x24 and 6x16 products. These are the conditions in which temporary spikes in spot market prices are most likely to occur and when the reliability of the electrical system is most likely to be strained.

Electric utilities typically construct peaking units, such as simple-cycle combustion turbines, to operate during such peak periods. While the department's portfolio features plenty of energy during the 6x16 on-peak period as a whole, the portfolio lacks a significant component of true peaking capacity to supply energy during peak demand or extensive generating unit outages. Although such peaking units may not operate often, particularly during years of favorable hydroelectric production, they can meaningfully reduce the likelihood of blackouts and significantly reduce the possibility of extreme energy price spikes driven by peak electricity demand. Given these factors, along with the mandate of AB 1X to secure reliable power, the amount of true peaking capacity in the department's portfolio appears to be significantly less than ideal relative to the shape of the estimated net-short position.

The amount of true peaking capacity in the department's portfolio appears to be significantly less than ideal relative to the shape of the estimated net-short position.

At the same time, a department consultant projects that its energy purchases during the 6x16 peak period will exceed the average net-short position during certain hours for several years. For example, a 6x16 contract will provide the same 16 hours of energy on a light-load Saturday in April as it will on a peak-demand day in August. The energy under contract during those hours that are not super-peak hours, often referred to as the "shoulder" period, in those years is expected to exceed needs and a significant fraction of it may well have to be resold at market rates that are well below the long-term contract price. The potential for an energy surplus is particularly high in the southern part of the state—south of the Path 15 transmission interface, which is the main transmission line between Northern and Southern California. For this region, a department consultant has estimated that the energy purchased under the long-term contracts will exceed the average net-short position during the 6x16 peak period between the last quarter of 2003 through the first quarter of 2005 by an average of almost 2,000 megawatts during some quarters. According to the department, it expects to exchange some of its excess power in these situations with power programs in the Pacific Northwest for power needed in other times due to the complementing needs of the two regions.

Figures 4 and 5 on pages 43 and 45 respectively, illustrate the fact that over the next decade, the department's contracts will fill a substantial fraction of the net-short energy and a more modest fraction of the net-short capacity. In light of the statutory mandate for reliability and fit to the overall energy load profile, the portfolio of contracts obtained appears to overemphasize year-round energy, underemphasize delivery during peak demand hours, and underemphasize capacity requirements as they change with time. In fact, given the problems in California's electricity markets—which focus on insufficient supplies and excessive prices during periods when demands are above levels that can be met by "base" supplies—a more effective strategy would have placed a greater focus on the procurement of supplies to meet daily and seasonal peak demands. As discussed above, implementation of such a strategy would incorporate a more careful analysis of the cost and risk implications of a balanced supply portfolio. This implementation, in turn, could establish a proper framework for contract price and perhaps other parameters to guide department negotiators in their efforts to build a supply portfolio that might better achieve the objectives of AB 1X.

The department acquired little by way of capacity contracts to respond to consumer demand during the most critical of future peak demand periods—summer and super-peak periods, and other times when the net-short capacity requirements might be unusually high.

The department has not provided us with the analysis to demonstrate that its initial strategy set specific cost or quantity targets for capacity supplies in critical peak periods. The strategy does emphasize new generation supplies to assist with the supply and demand balance. However, the department acquired little by way of capacity contracts to respond to consumer demand during the most critical of future peak demand periods—summer and super-peak periods, and other times when the net-short capacity requirements might be unusually high. This lack of specific emphasis on the critical peak periods in the initial strategy is noteworthy in light of the price and reliability problems operating at the time and the concerns regarding the summer of 2001. As the situation stands, unless the department implements a planning and procurement strategy that effectively anticipates its changing capacity requirements, the investor-owned utilities' customers remain exposed to supply shortages and purchases in spot and other short-term markets when prices are high. System reliability also might be threatened if insufficient generating capacity is available on short notice to meet the department's needs. These cost and reliability questions are exacerbated by concerns regarding the degree to which the department can actually depend on contract suppliers to follow through with capacity commitments during peak periods, as discussed in Chapter 2.

According to the department, it is considering various mitigation strategies for these risks and the extent to which the strategies will be successful is unknown at this time. For example, the department presently expects to fill energy needs in peak-demand periods with market purchases rather than more contract purchases. The premise behind this approach—adequate supply availability and low prices during these periods—may in fact occur and the strategy may be successful. However, it is also possible that the suppliers not under contract will choose to not make supply available, at least not for low prices. Also, the department hopes to exchange some of its excess power in low demand periods in California with the Pacific Northwest in exchange for power in high demand periods in California since the energy needs of the two regions complement each other. Due to the length of the time period, 10 years, and the uncertainty over what entity will be managing the net short, it is also important to note that whoever manages the net short could choose to put more of the peak-demand period needs under short- or long-term contracts if that entity assesses its risk for these periods differently than the department presently does.

The Department's Portfolio Provides a Relatively Constant Flow of Energy, but It Lacks the Flexibility to Substantially Reduce Purchases During Periods of Surplus or Low Market Prices

Not only can the relatively constant deliveries of energy cause problems for the department's portfolio during peak-demand periods, but those constant deliveries of energy may also be problematic during periods when the net-short loads fall to relatively low levels as these commitments also limit flexibility during periods when market prices fall.

The majority of the contracts provide for the delivery of firm energy, meaning that the department must pay for the power whether or not it is needed.

Most of the contracts in the department's portfolio provide for the delivery of firm energy. These contracts require the seller to provide energy in every hour of the specified period (such as the 6x16 or 7x24 contracts noted earlier) either from specific generators or from the market. Several contracts provide for unit-contingent sales, in which the department takes some of the risk of the power plant's (or unit's) not being available.

The portfolio of contracts also includes a mix of base, peak, and off-peak products. The portion of the contract capacity on a megawatts basis met by base products rises steadily from just over 16 percent in 2001 to about 61 percent in 2005. As we noted earlier, the department has assembled a portfolio of long-term contracts that in its peak year, 2004, will exceed 12,000 megawatts. Approximately 9,300 megawatts of this peak-year capacity comprises nondispatchable contracts that do not allow the department to minimize power costs through economic dispatch of the contract resources or through curtailing quantities that exceed the department's needs. No sizable utility system can perfectly match supply to load on an hour-by-hour basis; hence, all such systems end up selling surplus power at a price below their full cost from time to time. However, in the case of the department, the number and size of these sorts of transactions are likely to be amplified by the relative inflexibility of the portfolio, particularly because the net-short position is subject to significant volatility.

Figure 3, on page 42, is a hypothetical figure that illustrates how the relative inflexibility of the department's contracts can leave it exposed to high market prices in some instances and, at other times, can leave it with surplus energy. Amounts of contracted supplies from 7x24 contracts, about 22,000 megawatts in this example, provide a large fraction of the total energy in the annual load profile, only about 50 percent of the load in the peak hour, and more than the total load in several low-load

No sizable utility system can perfectly match supply to load on an hour-by-hour basis, but the department may end up selling power because of the large amount of nondispatchable power in the portfolio.

hours. An additional 10,000 megawatts of 6x16 contracts, combined with 7x24 contracts, provide an amount of energy nearly equal to the total annual energy requirement. However, due to the fact that the fit within the load profile is not precise, there remain periods in peak load where more energy will need to be purchased and other times when surplus energy will exist. A portfolio of supplies to meet the overall load profile must provide a mix of options to assure that load is met each hour. A mix of peaking supplies, dispatchable contracts, and standard 7x24 and 6x16 contracts along with spot market purchases would be needed to supply the overall load in each hour at the lowest cost.

The Department's Portfolio That Emphasizes Significant Amounts of Fixed Price Energy to Limit Volatility Also Limits Potential Portfolio Cost Savings if Power Prices Decline

The possible consequences of a power portfolio that relies heavily on spot market purchases are well known to Californians. Prices can move to extremely high levels, sometimes on a sustained basis, and they can also do the reverse. In other words, a portfolio with this makeup is highly variable and risky. At the other extreme, a portfolio that is based entirely on forward contracts and thus uses the spot market in only a limited way poses a different set of problems and risks. While such a portfolio provides protection against the risks of extreme prices, it also constrains the benefits to consumers should there be forces (such as declining gas prices, new capacity additions, or increasing conservation) that push prices down. Clearly, the extent to which there is both protection and constraint will depend upon the specifics of the contract portfolio. A portfolio in which all contracts are fixed in both price and quantity would be at one end of the spectrum, and one with prices that vary significantly with, say, the cost of fuel, will be at the other end.

The developer of a solid portfolio needs not only to determine what types of contracts to enter but also to decide on the overall allocation between forward contracts of various types and spot market exposure. After all, if contracts help to moderate the prices in spot markets, the benefit will accrue only if there are purchases to be made in the spot market. In short, a balance must be struck. There is no precision in these matters; however, developers can follow some reasonable guidelines. For example, in its December 15, 2000, order, the FERC notes that in other independent system operator markets—such as the New England Power Pool, the New York Independent System Operator, and the Pennsylvania–New Jersey–Maryland market—spot markets

represent less than 20 percent of the overall power transactions without being more definitive. The chairman of the ISO Market Surveillance Committee alludes to a spot exposure in the 10 percent to 15 percent range. Neither of the foregoing percentages should be taken as a prescription for the percentage that the department should have sought to achieve. On the other hand, a portfolio with spot purchases in the 10 percent to 20 percent range—along with more dispatchable and tolling agreements—would have allowed more of the benefits to flow to customers in the event that the department was successful in taming the market chaos.

In 2000 the California market, and in particular the investor-owned utilities' load, was overwhelmingly in the spot market. Action taken by FERC in December 2000 eliminated the requirement that the utilities simultaneously sell all of their capacity into the California Power Exchange and buy all of their load from the spot markets. This change almost instantaneously reduced the dependence of the utilities' portfolio on the spot market by about two-thirds. Thus, when the department assumed responsibility for the utilities' net short, nearly all of which was supplied by the spot market, the overall reliance on the spot market was about 30 percent. To attain the "less than 20 percent" threshold noted by FERC, at least one-third of the net short would need to be secured in forward contracts that were independent of the spot markets. On the other hand, contracting to remove more than two-thirds of the net short would reduce the role of the spot market to less than 10 percent of the overall supply portfolio.

The department has a limited ability to lower the average cost per kilowatt-hour of its supplies by blending high-cost contract purchases with future potentially low-cost spot purchases.

The department's consultant has projected that the percentage of the overall load purchased in the spot market will gradually decline until 2004 and 2005. Thereafter, it will increase gradually again until 2010. On average through 2010, this amount represents 9.5 percent of the utilities' overall load and, as we indicated earlier, less than 9.5 percent of the State's entire load.

As a result, the department has a limited ability to lower the average cost per kilowatt-hour of its supplies by blending high-cost contract purchases with future potentially low-cost spot purchases. This situation has improved somewhat by the inclusion in the portfolio of contracts with pricing structures that follow trends in gas markets, which have a large impact on spot market electricity prices; however, the use of these contracts is likely to be offset by the fact that the net short accounts for one-third of the investor-owned utilities' total energy requirements. Stated

A procurement strategy that targeted a higher percentage of spot market purchases and/or more dispatchable and tolling agreements would have provided more opportunity for consumers to benefit from the expected fall in spot market prices.

differently, retail electricity consumers are unlikely to benefit significantly from the expected fall in spot electricity prices over the next 10 years because spot market purchases will range between 4.2 percent and 17.4 percent, but on average they will account for 9.5 percent of the utilities' total energy requirements during that period. In any event, a procurement strategy that targeted a higher percentage of spot market purchases, more dispatchable agreements, or more tolling agreements, or all three, would have provided more opportunity for consumers to benefit from the expected fall in spot market prices.

The department may have had good reason to consider limiting commitments of forward purchases of electricity. In early 2001 natural gas prices were at very high levels, new capacity was slated to come on-line in the near term, and the ISO was implementing demand response programs. Electricity prices in spot and forward markets have, in fact, fallen precipitously in the period since the contracts were signed.

The Department Purchased Too Much Power in Southern California

As we noted earlier, the department's consultant estimates that the amount of capacity under contract to serve loads south of Path 15 from the fourth quarter of 2003 through the first quarter of 2005 will exceed the average peak-period demands there, resulting in significant energy surpluses. In some quarters the available capacity is estimated to exceed average peak demand by almost 2,000 megawatts, even after the department reduces the amount purchased from dispatchable resources. A key reason that the location of so many megawatts of capacity in Southern California is a problem is that there is insufficient transmission capacity to move the power north to meet the needs in that area. The department has recently confirmed that it has excess capacity south of Path 15 and would like to locate new supplies north of Path 15.

Because market prices are now projected to be substantially below the average cost of the portfolio during this period, power that is sold at a loss must be recovered from consumers of the investor-owned utilities through higher electricity rates. As we noted earlier, and as we discuss in Chapter 3, all systems will have excess power from time to time and will make off-system sales at less than full cost. However, there is a difference in magnitude between the need to make occasional sales and having excess resources of almost 2,000 megawatts.

The department will likely have to sell the excess power with any loss passed to consumers.

While the cost to consumers of this surplus will depend on many factors, we are concerned that it could be substantial. By way of example, if the average surplus during the 5,000 peak-period hours in 2004 were 500 megawatts and the difference between on-peak contract prices and on-peak market prices was, say, $30 per megawatt-hour, the cost to consumers would be approximately $75 million. Different assumptions would, of course, yield different results, but the numbers are not likely to be small. This could have been avoided—or its rate impact mitigated—had the department limited the amount of the net short met by 6x16 peak products, undertaken a more comprehensive risk analysis of the need for power in the State, or both. The department could have then incorporated those findings in its portfolio design. Alternatively, the department might have sought to procure more dispatchable supplies, so as to allow for reduced purchases during periods of excess energy. According to the department, the portfolio design did not consider the Path 15 transmission line as critical a factor as it ultimately became because the department relied upon proposals existing in February 2001 to fix the problem and it believed that the Path 15 upgrade would be successful in time for its power purchases beginning in 2003.

The United States Department of Energy is leading a project to upgrade the State's Path 15 transmission corridor by building a new 500 kilovolt line that will add 1,500 megawatts of transmission capacity at an estimated cost of $300 million. While this line may alleviate some of the problems created by the department's contracting effort, the line will not be operational until at least the summer of 2004, which is the peak year for the department's energy surplus. Thus, any slippage in the project could substantially reduce the lines' effectiveness as a cost mitigation tool. Clearly, the later the line is placed in service, the greater the impact the rate increase associated with the energy surplus will have on retail customers.

The Department's Portfolio Includes a High Proportion of Contracts With Natural Gas Generation but Limited Opportunities to Take Advantage of Falling Gas Prices

To cope with risk in a volatile fuel pricing environment, portfolio planners may want to ensure that the cost of the supply portfolio and the cost of natural gas, the primary driver of spot market prices in California, do not diverge to an unacceptable degree. Planners can accomplish this task by including tolling agreements in the portfolio. Under a tolling agreement, the buyer of power produced by a generation facility pays a fixed fee—a

toll—to have the right to convert fuel that the buyer owns to power. Under such an agreement, a power buyer, such as the department, is also the purchaser of the fuel supply.

As early as February 7, 2001, a department consultant projected significant decreases in natural gas prices from 2002 through 2010, yet only 30 percent to 40 percent of contracts include provisions designed to follow trends in gas prices.

Each year after 2001 the department will have between 30 percent to 40 percent of the contracted capacity in megawatts coming from contracts with pricing provisions designed to follow trends in gas prices, which will provide the opportunity for consumers to benefit meaningfully from falling gas prices. Nevertheless, the department could have procured more of these contracts to take advantage of the projected decrease in natural gas prices. We can see this potential benefit by looking at the effect that decreases in the price of natural gas would have on the total cost of the portfolio. Gas prices spiked to high levels in December 2000 and January 2001. However, as early as February 7, 2001, a department consultant projected significant decreases in natural gas prices beginning in 2002 and continuing to 2005, with the lower prices lasting to 2010, the last year of the projection.

In July 2001 the department's consultant used a base-case projection of future gas prices to value the department's contract portfolio. In addition, the consultant also prepared a low-case projection that indicates significant reductions in gas prices relative to the base case in 2002 through 2005, ranging from 19 percent to 44 percent, and slightly more modest reductions in the later years, ranging from 10 percent to 12 percent. Using the consultant's low-case projection to replace the base-case projection would lower the cost of the power portfolio by about $1.9 billion, or 4.5 percent of the total portfolio cost. This result can be attributed to several factors, the most important of which is that between 30 percent to 40 percent of the energy delivered each year to the department after 2001 is subject to prices that vary with the price of gas. Had a greater percentage of the contracts included tolling agreements, the projected savings from natural gas prices would have been greater. A second important fact is that many of these agreements include demand, operating and maintenance charges, or both, and these factors are not indexed to gas prices. As a result, when gas prices fall, these components of the power bill remain fixed. Of course, as the gas price projections change, the effects they have will change too. But the principles articulated here are unaffected. According to the department, before receiving an opinion from the attorney general on February 28, 2001, affirming its authority, the department was not certain that AB 1X authorized it to purchase the natural gas supplies required under tolling agreements.

The department's consultant also prepared a high-case projection of gas prices. Using this projection, which reflects the possibility of high gas prices relative to the base case, raises the portfolio cost by $1.6 billion, an increase of 3.8 percent. However, the consultant's low-case projection appears closer to current natural gas prices.

The majority of the contracts have pricing structures that feature fixed prices. While some of these contracts include fixed capacity charges, with energy (or production) priced separately, most include only a single charge or a schedule of charges for energy and capacity together. In addition, as we just discussed, a number of tolling agreements with pricing provisions provide for the pass-through of gas costs incurred by the sellers or that allow the department to purchase the gas used in the sellers' generators. Table 4 shows the amount of capacity each year associated with contracts that have tolling or gas price index provisions.

TABLE 4

Annual Capacity Associated With Tolling Agreements or Indexed Prices (In Megawatts)

	Calendar Year					
Contract Type	**2001**	**2002**	**2003**	**2004**	**2005**	**2006–10**
Tolling + Market	3,531	2,442	4,162	4,712	3,487	4,206
Fixed prices	2,685	5,596	6,856	7,315	7,165	6,237
Totals for all contracts	**6,216**	**8,038**	**11,018**	**12,027**	**10,652**	**10,443**

Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

Despite Legislative Desire and the Department's Offer of Attractive Contract Prices, the Portfolio Includes Little Renewable Energy

Although not mentioned specifically in AB 1X, a large power supply portfolio should also reflect diverse supply options, particularly with regard to fuel source and technology. A diverse fuel and technology mix helps ensure reasonably reliable supplies and stable prices because this mix can help mitigate against cost increases in one fuel or performance problems with a particular technology. Renewables displace fossil fuels, in this case, natural gas, and by doing so can moderate spot prices, a major objective

of AB 1X. Also, renewables generally produce less pollution than other sources of energy, such as natural gas or coal. Given the pollution concerns in the State, AB 1X specifies a "desire" for the department to secure as much power from renewable resources as possible.

Only six contracts totaling 2 percent of all megawatts purchased were from renewable energy sources.

Unfortunately, the portfolio includes only six long-term contracts for renewable power, with relatively few megawatts overall. These contracts total 230 megawatts, and include two contracts totaling 31 megawatts for biomass power, one 25-megawatt contract for geothermal power, and three contracts for a total of 174 megawatts of wind power. Together, these contracts account for 2 percent of the approximately 12,000 megawatts of capacity contracted for in the peak year of 2004. The terms of these contracts range from 2.5 years to 12 years. The weighted average wholesale price for renewable energy is $67 per megawatt-hour, which compares favorably to the average wholesale price of $70 paid by the department for nonrenewable energy. According to the department, the proposals for renewable energy were few relative to those for nonrenewable energy and most of the developers did not follow through with their proposals.

Although that goal of securing power from renewable resources has not been met to date, the Consumer Power and Conservation Financing Authority (power authority) has indicated that it signed letters of intent with generators to provide approximately 2,300 megawatts of renewable wind, geothermal, and biomass capacity, of which about 1,600 megawatts are located south of Path 15. However, while this new capacity would have been competitive with the prices demanded by suppliers of nonrenewable energy during the first phase of the negotiations, it is unlikely to be competitive with today's spot market prices. Moreover, in a recent letter to the power authority, the department indicated that the addition of this capacity would exacerbate the already serious excess capacity problem south of Path 15. Thus, the extent to which the power authority's efforts will add further projects with renewable energy remains to be seen. Further, despite the legislative mandate to secure as much renewable power as possible, the department did not do so in its contracting efforts and missed a significant opportunity to add environmentally friendly power.

THE DEPARTMENT'S FAST PACE PRECLUDED IMPORTANT PLANNING AND ANALYSES, CONTRIBUTING TO CONTRACT PORTFOLIO PROBLEMS

In assessing the implementation of the department's strategy, observers must bear in mind the magnitude of the task and the pace at which it was performed. A significant portion of the net short was covered with long-term contracts that were negotiated in a short time. Decisions committing the customers of the investor-owned utilities to $35.9 billion in future power-purchase obligations were made in 30 days. In this context, the decisions regarding the number, duration, and types of contracts in the portfolio were significant to the cost and outlook of the long-term power supply. Contracts of this magnitude, negotiated at a rapid pace, create the potential for costly errors or omissions.

All of this, of course, must be viewed in the context of the conditions at the time: Prices were at historic highs, and the department lacked leverage in the market to enter into favorable contracts. As Figure 6 on the following page shows, the monthly average of spot market prices in the power exchange had reached more than $300 per megawatt-hour in December 2000 in Northern California, and prices paid by the department ranged between $180 to more than $300 per megawatt-hour through May 2001, after the power exchange closed and most of the current contracts had been completed. By contrast, the average spot price ranged between $11 and $53 per megawatt-hour from April 1998 through April 2000.

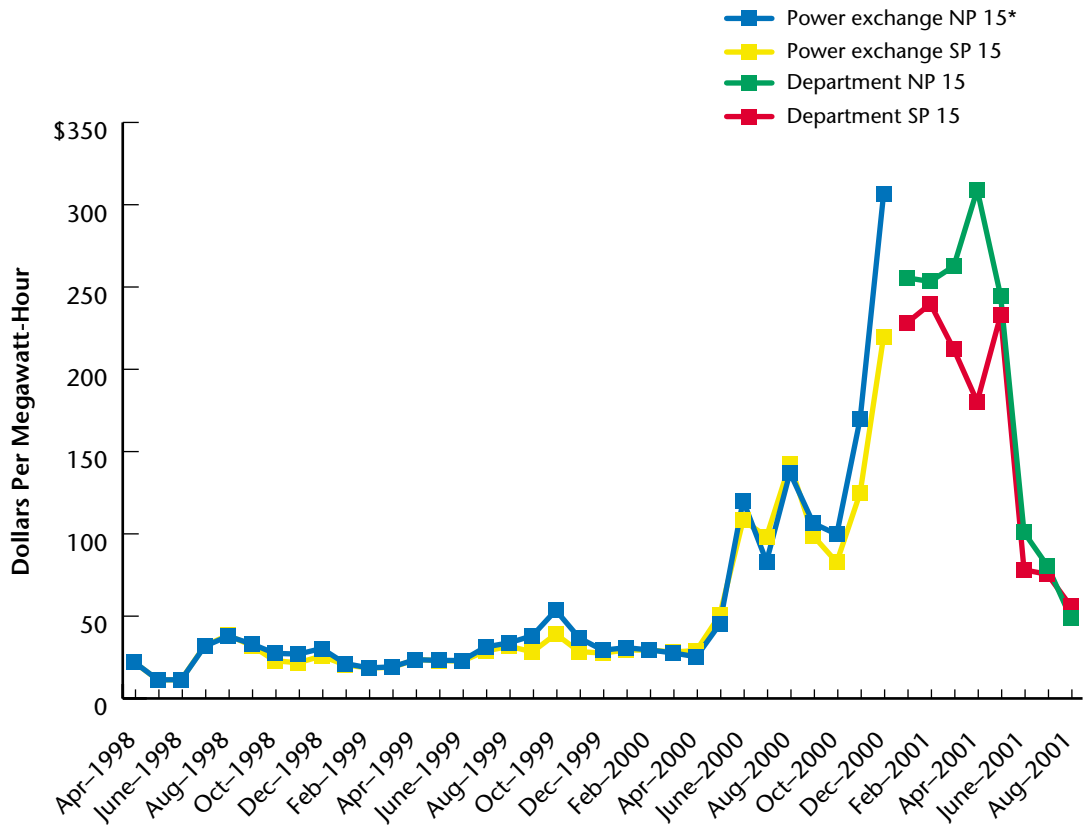
The Market and Financial Crises Played an Intangible but Significant Role in the Rush to Enter Long-Term Contracts

The approach that the department pursued appears to have been based on the belief that entering into long-term contracts was the only way to stop the hemorrhaging in the spot markets. The ISO had expressed a concern that a solution to the market problem was needed by the summer of 2001 to avoid a catastrophic outcome.

Although it is clear that the department's focus on long-term contracts was warranted, it is not entirely clear why the contracting effort went so far so fast. The contracting activity carried out in February committed the State to the majority of the contracts and billions of dollars in direct contract expenses in 30 days of negotiations; the estimated total cost for all contracts signed, not just those in the first 30 days, is approximately $42.6 billion over 10 years.

FIGURE 6

California Spot Prices for Electricity
April 1998 Through August 2001



Source: Data from the California Power Exchange and the Department of Water Resources.

* NP 15 and SP 15 mean the areas north and south of the Path 15 transmission line, respectively.

When AB 1X was enacted, the market was in chaos and the financial condition of the major entities—the investor-owned utilities, the ISO, and the power exchange—was, to say the least, extremely weak. It was widely believed that the root causes of the problem were the withholding of power that was otherwise available and, related to this, the skyrocketing prices for electricity. The department and the negotiating team saw the challenge in effect, as changing the market philosophy of suppliers from short-term transactions to long-term transactions and price stability.

The department had to weigh the risk that the market would remain out of control absent the contracts against the risks inherent in signing many contracts quickly.

The situation was unprecedented. Clearly, the department believed that the market could not change significantly unless the State contracted for a significant amount of long-term power extremely quickly. The department had to weigh the risks inherent in signing many contracts quickly against the risk that the market would remain out of control without the contracts. In any event, the view of the department and the negotiating team—given their perspective at the time—was understandable based on economic theory.

There is, however, no one-to-one relationship between the need to move quickly and the decision to sign about 40 major contracts in just 30 days. The department has not provided us with documentation that demonstrates how it determined the number of contracts, the number of megawatts, the amount of energy, and the pace at which it moved to make these commitments. In short, this procurement strategy was, and remains, solely a product of the department's judgment made at the time.

One must, however, counterbalance the decision by the department with the decision's inherent risks. In other words, whatever the benefits associated with the strategy, moving so quickly also presented risks. These risks included the inability to plan adequately and to consider a broad array of contract options as well as the potential for overcommitting during a time when prices were at unprecedented levels. Given the magnitude of the contracting effort—thousands of megawatts, some for several years—these risks are a major issue.

Today, concerns about the markets remain, but the potential for catastrophic outcomes is much lower. However, the extent to which this moderation of the market crisis is a result of the department's long-term contracting efforts is much more in question. In August 2001 the ISO cited a number of actions, that in its opinion, taken over the course of 2001 contributed to mitigating the crisis, including the following:

- FERC's market mitigation order of June 2001.
- Relatively low system loads.
- New generation coming on-line.
- Fewer outages among existing generation units.

- Lower natural gas prices.

- Substantial forward contracts purchased by the department, reducing reliance on real-time transactions to meet the load.

Thus a number of events were occurring simultaneously that could have an effect on power markets. Given this convergence of factors, the ISO concluded that it could not at that time determine the extent to which the observed reductions in spot market prices were due to any one of these factors, including the department's contracting efforts.

The Department Initially Lacked the Needed Planning Capabilities but Developed Those Capabilities Over Several Months

Before the passage of AB 1X, the department was a state agency whose primary responsibility was water supply. Its load of approximately 2,400 megawatts was quite substantial for a single customer, and it did a relatively small amount of purchasing and selling. For context, the department's consultant notes that its size would make it equivalent to approximately the sixth largest public power utility in the country. Thus, it had some familiarity with the workings of the California electricity market. However, it did not have (and did not need to have) the extensive planning capability required to perform adequately the planning tasks for the statewide power portfolio required under AB 1X.

The department's own lack of an ongoing planning system was compounded by the fact that no other load-serving organization in the State was actively engaged in this type of contracting and planning. Until mid-December 2000, the investor-owned utilities had been allowed only limited participation in the long-term forward markets except for the authority to purchase some block-forward contracts and they had no need for long-term planning for the net-short supplies since those supplies were to be bought on the spot market. In addition, while unanalyzed information (such as load forecasts and generation data) was available to the department from the investor-owned utilities, the utilities did not provide market studies or analysis sufficient for this type of planning.

The department brought in expert consultants to perform market analysis, but it took them several months to develop the level of sophistication in the planning models, methods, and data needed for procurement operations of this scale.

The department brought in expert consultants early on to serve the power market analysis function for the effort. However, it took the consultants several months to develop the level of

sophistication in the planning models, methods, and data typically used in market planning for procurement operations of this scale. The interim planning methods employed more simplified spreadsheet models and proxy methods to assess the net short and to perform market price analysis. The fast pace of negotiations precluded the development or use of more sophisticated tools (such as a market price projection based upon state-of-the-art modeling tools) to evaluate the economics of the bids submitted by sellers and the subsequent terms resulting from negotiations in February and March. Such tools allow for a more systematic assessment of the implications any contract might have for the costs of the evolving portfolio. According to the department's consultant, more importantly, the need to initially purchase significant amounts of various types of power precluded the need for sophisticated tools early in the procurement effort that would become necessary later to fine-tune the portfolio. By June 2001 the department and its consultants had completed the development of a market simulation model and began using it for net-short analysis, market assessments, and support of the revenue bonds.

The Department's Initial Planning Did Not Adequately Address Market Risk Factors Through Analyses of Alternative Outcomes

The decision to combine heavy long-term contracting with a fast-paced negotiating strategy exposed the department and the investor-owned utilities' consumers to substantial market risks.

The decision to combine heavy long-term contracting with a fast-paced negotiating strategy exposed the department and the customers of the investor-owned utilities' to substantial market risks. These risks included those associated with the uncertain amount of energy that would be needed (that is, the possibility that the contract quantities would differ from the actual load requirements); those associated with the uncertainties of future market prices (that the contract costs would exceed market levels); and the potential that the mix of products would not adequately meet the overall needs of the load profile. The rapid pursuit of long-term contracts in the first two months of the power-purchasing program precluded a more extensive, more accurate analysis of the need for power in the State until well after most of the large contract commitments had been made. According to the department's consultants, the forecast of the net short used as the basis for the initial contract negotiations was based only on the data readily available at the time and, given the pace, involved only a limited assessment of the risk factors or key uncertainties.

In addition, AB 1X placed the department in a position that required it to be the manager of load risk in the near term, as well as a buyer of energy. Thus the department assumed responsibility for one-third of the load as well as for virtually all of the load risk or volatility in the utilities' portfolio. Hour to hour, the department must supply all load not met by the utilities' generation, and this amount can vary significantly as a function of the availability of utility generation and load swings. With the responsibility for the net short through 2002, the department has the responsibility to manage that market risk operationally. In the longer term, the department's contract commitments will have a substantial effect on the market risks borne by the consumers.

Early in the procurement process, the department's consultants identified the department's need to develop quality capabilities for market risk assessment. These included the ability to conduct scenario analysis to evaluate the department's risk position under various market conditions. The department also readily recognized that the lack of good risk management capabilities was potentially costing the power-purchasing program substantial amounts of money and that the portfolio of contracts signed early on carried substantial risks that would need to be assessed and managed. In formulating a risk management plan for the department (a plan that the department is now developing for implementation), its consultant noted:

> "It is industry standard that an energy transacting organization at a minimum be able to: 1) calculate the replacement value of a position/contract, 2) be able to calculate a value at risk on its portfolio or subset of the portfolio, and 3) be able to perform scenario analysis/ stress testing of the portfolio. DWR [The Department of Water Resources] should at a minimum be able to comply with industry standards, or will otherwise be open to public criticism and potential audit exposure."

However, these principles, which focused on the management of the large portfolio of contracts secured by the department, were not well applied to the initial contract decisions that created the portfolio. On April 12, 2001, a newly formed department contract and planning committee began to recognize load risk issues:

> Generally the current analysis suggests that no further 7x24 baseload product is necessary in either NP 15 or SP 15. In fact, considering the anticipated reduction in

demand resulting from conservation, the SP 15 need appears to be substantially met by these proposals presently included in the analysis.

These issues are similar to the portfolio imbalance issues noted earlier in this chapter and indicate that the initial contracting decisions were a substantial contributor to those problems.

Some of the factors that could not be assessed quantitatively in the initial contract decisions in February and March, due to time and planning capability constraints, include the following:

- Volume risks deriving from uncertainty in load projections, uncertainty in utility generation, the inherent volatility of the net short, and the cost implications of, for example, more effective conservation and demand management programs and price elasticity effects associated with the price levels of the contracts.

- Market price risks associated with changes in gas market conditions, market mitigation measures at FERC, and the impacts of new supplies.

While the department obtained load and generation data for the investor-owned utilities, we saw no evidence of its working with the investor-owned utilities to design a contract portfolio to complement the utilities' power generation. From a risk management perspective, better coordination would have helped.

In the initial contract decisions, the lack of formal assessment of these factors was intensified by the scale of the effort relative to the net-short load and the total dollar amount of the commitments made. The risks associated with the contracts' inflexibility must counterbalance any benefits to the portfolio from the contracts particularly where the load (net short) estimate is not as precise as it could be if further analysis was performed. Other potentially beneficial negotiating strategies that did not take place early on, evidently because of the decision to have the fast pace of the negotiations, included (1) limiting the availability of longer-term deals (ones lasting more than 3 to 5 years) to dispatchable or tolling agreements, or both; and (2) signing agreements with the most attractive bids first, then slowing the contracting pace and making subsequent commitments based on a more comprehensive analysis.

A recent CPUC order regarding direct access could significantly reduce the net short, causing the department to become a seller of excess energy in 2002.

An example of the implications arising from the limitations in the planning process is the CPUC's recent order (Decision 01-09-060) suspending the option for direct retail access contracts (contracts that power customers enter with alternate suppliers) entered after September 20, 2001, instead of much earlier, as the department had expected. Before that decision, the department's consultant had projected that spot market purchases would account for a declining percentage of the total utility load from 2001 through 2003. The CPUC's decision changed that projection significantly. The amount of the utilities' load met by direct access could be greater than previously projected, causing a corresponding reduction in the department's net short. This reduction could be large enough to cause the department to swing from being a large purchaser of spot market energy in 2002 to becoming a small but growing seller. Analyses of potential scenarios that included load risk events such as this would have been prudent, and they could have affected the development of the department's portfolio if the analyses had occurred in a timely manner and relied upon.

We wish to emphasize that the concerns expressed here regarding the department's planning just after the passage of AB 1X are related to timing. At the outset, the department itself was ill equipped to handle the planning tasks needed for the procurement authority assigned to it by the statute. Considering the magnitude of the tasks, one could hardly expect otherwise. However, the department did quickly find consultants that had the expertise to provide needed analytical capabilities. These analyses are not simple, and many require a great deal of data; hence, it appears that they could not be done adequately with a speed that matched the tempo of the initial contract negotiations in February and early March 2001.

In the first six weeks of the program, the department's market risk assessment appears to have been simply a belief that the risks of continued crisis in the power market outweighed the risks associated with going forward quickly with the negotiated contracts. Little market assessment occurred. Indeed, given the speed that the department decided was necessary to react to the crisis, little market assessment was possible. However, we found no analytical basis for the choices of the amounts, types of products, or pace of the negotiations for the contracts entered in that period.

Once the initial contracting phase was complete, the department, with its consultants, made a concerted effort to develop the portfolio planning and risk management capabilities needed to manage the large contract portfolio it had acquired. The planning models, methods, and information employed now are markedly improved over those initially used in March and April 2001. The department began installing an energy transacting and risk management system in November 2001, and it plans to develop further its market planning models and methods to move closer to the industry standard referenced earlier. ■

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CHAPTER 2

The Terms and Conditions of the Majority of the Long-Term Contracts May Not Meet the Reliable Energy Goals of Assembly Bill 1X

CHAPTER SUMMARY

The majority of the long-term contracts entered into by the Department of Water Resources (department) with power generators do not include the terms and conditions that one would expect to see in contracts meant to ensure the reliable supply of energy. A key goal of Assembly Bill 1 of the 2001–02 First Extraordinary Session (AB 1X) was for the department to obtain a portfolio of power contracts to provide a reliable source of power at the lowest possible cost as a means of addressing the unprecedented financial and supply crisis in the electricity markets in the State. Another key goal was to establish a creditworthy buyer in a market where the State's three largest investor-owned utilities, all facing crippling financial problems, could no longer buy all the power necessary to keep electricity flowing in the State. To fill the void, AB 1X placed the department in the unique role of the buyer of the unmet demand, or net short, and authorized the department to, among other things, enter long-term power purchase contracts. The department was successful in establishing itself as a creditworthy buyer, as evidenced by the numerous long-term contracts it has entered into. However, the legal terms and conditions of those contracts, particularly the early ones, may not adequately assure that the generator will physically deliver the electricity the State needs to keep the lights on, especially in periods of tight supply and high prices. Moreover, the department continues to face creditworthiness concerns because the bonds have not yet been issued.

When measuring the adequacy of the terms and conditions of the contracts, we tested them against the conditions that prompted the State to engage in the purchase of electricity—that is, we tested whether the contracts assure reliable delivery of power in times of high prices and tight supply. Our detailed review of 19 transactions, consisting of 61 percent of the total gigawatt-hours purchased, and a screening of others concluded that the majority of the power is under contracts that may not

assure that reliable sources of power will be available to the department. In other words, when the market price for power increases above the contract price and demand for electricity exceeds supply, the terms and conditions of a majority of the contracts may not ensure that the department will be able to provide the power needed in California.

Under most of the contracts, the department cannot terminate the contract or assess penalties even if generators repeatedly or deliberately fail to deliver power at times when the State is in dire need of it. Instead, the department is limited to recovering the difference between the contract price and the cost of the replacement power, known as cover damages. While the department views cover damages as an adequate remedy to assure reliable physical delivery of power, we think that limiting the remedy to cover damages assumes that the buyer is concerned more about price stability than about assuring reliable physical delivery of power. The reliance on cover damages also assumes that an adequate supply of power will be available from which the buyer can purchase replacement power—but as demonstrated in 2000 and 2001 that may not be a valid assumption in the current California energy market. A better remedy would have been the right to terminate contracts with generators that repeatedly fail to deliver. Such a provision would have given the department the additional leverage to compel generators to deliver power even when it was uneconomical for them to do so or replace that unreliable generator with a new reliable generator.

The contracts' terms and conditions may not meet other reliability goals of the contracting effort, including ensuring that generators are making appropriate progress in building the facilities that will supply the power the department has contracted for and allowing the department to inspect generating facilities. Moreover, contracts in which the State pays a premium for construction of new generation may not ensure that the new generating units will be built and that the power will actually be made available and delivered.

Although the department was in a weak bargaining position because of the financial crisis in the electricity markets, in its rush to ease the electricity crisis by locking in power supply through long-term contracts, it weakened its position even further by not requesting from the outset industry-standard contract terms and conditions that would have better assured reliable delivery of power. Instead, we found that the majority of the department's power is under contracts based on a model

that is primarily designed for power traders who trade electricity on the floors of deregulated wholesale electricity markets and not for parties, like the department, that have an obligation to buy the physical power needed to serve the electricity needs of the State. The fact that the form contract treats the purchase of electricity as a financial transaction is exemplified by the limited remedies available to the department against a generator who fails to deliver power under its contract. The form contract selected by the negotiators, including the legal team, was primarily tailored for energy traders and generators, when it needed to be closer to the contracts used by other purchasers of the volatile net short, such as the California Independent System Operator (ISO) or a utility with an obligation to meet consumers' demand for electricity. Indeed, utility professionals have recognized that this form contract may require modifications when used by an entity that has the absolute responsibility to ensure reliable physical deliver of power.

We found that even early in the bidding process, some sellers' unsuccessful bids included industry recognized terms and conditions that would have better assured reliable delivery of power. Because the department apparently did not ask for these terms until after the bulk of the deals had been made, we cannot determine whether the department would have been able to obtain more favorable reliability terms in the long-term contracts. We did note that the terms and conditions improved in the long-term contracts negotiated after March 2001; however, the vast majority of the power, amounting to $35.9 billion, was negotiated before March 2, 2001, the period in which we found that the terms and conditions regarding reliability of power delivery were least favorable to the State.

THE TEST OF THE CONTRACTS' ADEQUACY IS WHETHER THEY WILL ASSURE RELIABLE DELIVERY IN TIMES OF HIGH PRICES AND TIGHT SUPPLY

The mandate that AB 1X issued to the department was to contract for the power necessary to keep the lights on in California at the lowest possible price per kilowatt-hour. When AB 1X was enacted in February 2001, rolling blackouts and the skyrocketing cost of power threatened the economy of the State and the safety of its citizens. California became engaged in the power business and has entered into contracts of more than $42.6 billion to address these problems.

The assessment of the contracts is not simply their impact during the summer of 2001 but rather how their terms and conditions will affect California over the next 10 years.

The critical question in evaluating whether the terms and conditions of the long-term contracts assure reliable delivery of power should therefore be, if high prices and tight supply return to the California market, do the contracts ensure that California will be able to keep the lights on at a reasonable price? The mere fact of entering into the contracts may have brought the market under control, at least temporarily. However, the duration of the majority of these contracts is 5 to 10 years, and the amount of capacity under contract increases in 2003 to 10,000 megawatts or more per year through 2010. Thus, we need to base our assessment of the contracts not simply on whether they "worked a cure" in the market during the summer of 2001, but rather on how their terms and conditions will affect California over the next 10 years.

According to the department, the fact that not a single seller with power delivery obligations in 2001 failed to deliver power, even though market prices at times exceeded contract prices, provides objective evidence that the contracts assure reliable delivery of power. However, because the market price of power in the period beginning June 2001 was generally lower than the average price in the long-term contracts that were beginning delivery at that time, and because the start date for the delivery of much of the power is not until 2002 to 2003, we question whether the circumstances of the summer of 2001 truly tested the reliability and enforceability of the contracts. Further, when the market price is lower than the contract price, price alone causes the seller to deliver as much power as possible.

On the whole, we found that the terms and conditions of a majority of the long-term contracts may not meet the reliable energy goals of AB 1X. Particularly with respect to the large contracts agreed to before March 2, 2001, we believe it is the highly favorable financial deal for the generators, rather than the terms of the contracts themselves, that will cause the generators to continue to perform and are the basis of their long-term reliability.

The Contract Terms Should Reflect the Goal of Establishing a Creditworthy Buyer to Ensure Reliable Delivery of Power

In the drafting of any contract, the first questions to ask are: What is the purpose of the contract and what core provisions are necessary to make the deal worthwhile? In other words, the problems the contract seeks to resolve should define the terms and conditions of the contracts one enters into. Thus, gaining an understanding of the problems the State sought to resolve by

providing the department with authority to enter long-term power contracts is the starting point for defining the department's contracting goals.

When AB 1X provided the department with that authority, an unprecedented financial and reliability crisis existed in the power markets. The generators had no confidence in the ability of any entity to pay for energy delivered for California's consumers, a concern that had merit. Given the financial problems of the investor-owned utilities and the collapse of the California Power Exchange, as well as the fact that the ISO's ability to pay was dependent on the investor-owned utilities, the generators' concerns about payment were both real and substantial. Elected officials and electricity consumers were deeply suspicious of the generators and believed that they were deliberately withholding power to drive up prices. After the rolling blackouts in January 2001, usually a time of lower power demand, there were widespread predictions that the summer of 2001 would bring hundreds of hours of blackouts, which would jeopardize the health and safety of the citizens of the State and place financial burdens on business.

The solution contained in AB 1X was to make the department a creditworthy entity so that it could purchase the power necessary to keep electricity flowing in the State.

The solution contained in AB 1X was to make the department a creditworthy entity so that it could purchase from the generators the power necessary to keep electricity flowing in the State. The statute tried to quell the generators' fears about not getting paid by giving the department the authority to issue bonds that it would use to pay for its power purchases and to establish a method that would pass the costs of the program on to ratepayers.

AB 1X gave the department broad authority to enter into contracts to purchase electricity, with some general guidelines stated under Section 80100 of the Water Code. The first directive in this section calls for "contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour." Most of the remaining guidelines indicate the types of power the department should purchase to supply the overall energy portfolio, such as renewable power, as discussed in Chapter 1. In view of the overarching goal, we have focused on analyzing how well the terms of the contracts achieve the goal of providing reliable service. Whether that reliability was purchased at the lowest possible price is really a function of the particular product purchased.

Further, the lowest possible price is not necessarily a single rate for power, such as 6 cents per kilowatt-hour. Different power products have different lowest possible prices. For example, power purchased with the highest reliability guarantees is more expensive than power that a generator can deliver at will or with fewer guarantees. If the generator promises to deliver only if its plant is operating or when gas prices are below a fixed dollar amount, that power will be less expensive than if the generator promises to physically deliver power to the buyer even if its plant is closed due to a natural disaster.

The "lowest possible price" is not necessarily a single rate for power (e.g., 6 cents per kilowatt-hour). Different power products have different "lowest possible prices."

Other factors affecting the price include the hours of the day and the months of the year the power is delivered and whether the buyer has the option to refuse the power if it is not needed. For example, if the buyer contracts to purchase power 24 hours a day, 7 days a week, regardless of the buyer's need (known as a base-load, take-or-pay contract), the price is significantly lower than if the buyer contracts to purchase the power only at super-peak times in the summer months when the buyer needs it (known as a peaker-power, dispatchable contract). In the 24-hour base-load product, the generator has no down time and thus recovers its investment as quickly as possible. With peaking power, however, the generator's plant stands idle until the buyer demands the power, and thus the price must be increased to reflect the time that the investment in the generator is simply on hold, waiting for the buyer to dispatch the power. To use an analogy, it is the difference between the monthly cost of a long-term lease of an automobile as opposed to the hourly charge of having a taxi stand by until you are ready to leave.

In the first chapter, we addressed the cost risks in the contract portfolio. In this chapter, in which we review the legal terms of the contracts, our focus is on the kinds of energy products and reliability terms the department needed to perform its particular mission in the California power market.

The Crisis in the Energy Markets Led to the Department's Unique Role in the Marketplace as the Creditworthy Purchaser of the Net Short

Our evaluation of the department's performance must focus on the unique role in the California market that AB 1X called on the department to fill. The question is not whether the department purchased a power portfolio under terms and conditions that would suit a power broker or any particular utility. Instead,

the question is whether the terms and conditions of the contracts as well as the portfolio itself address the fact that the department was and remains the only entity financially able to assure continuity of electricity supply to California's homes and businesses. In other words, while the investor-owned utilities retained the obligation to supply power to their customers, financial constraints precluded them from making the power purchases necessary to do so. The department thus became responsible for the load risk of all of the investor-owned utilities—in effect assuming the role of supplier of the net short.

In acquiring this unique role, the department assumed only one-third of the overall load but became responsible for virtually all of the volatility in the load. That is, hour to hour the department must supply all load not met by the investor-owned utilities' electricity production (from their own generation or from existing contracts that they hold). This unmet load, which is known as the net short, can vary significantly due to changes in generation available from the utilities (from unexpected plant outages, for example) and load swings (resulting from unanticipated changes in the weather and other factors). While the ISO retains the responsibility to balance the load, it is the department's job, as the creditworthy purchaser, to buy the necessary power to keep electricity flowing for the citizens of California served by the three largest utilities.

The Department Was Under Pressure to Contract for as Much Generation as Possible and as Quickly as Possible

The State's General Fund was hemorrhaging as California spent over $500 million in January and $1.4 billion in February for short-term power.

There was another high-priority mission that was not explicitly stated in AB 1X: The State wanted those long-term contracts signed immediately. The State's General Fund was hemorrhaging as California spent over $500 million in January and $1.4 billion in February for short-term power. Signing up the generators to contracts as quickly as possible was viewed as the only way both to limit the State's daily energy expenditures and to gain control of the market. In a press conference on January 26, 2001, Governor Davis commented on the goals of the team he had appointed to negotiate the long-term contracts, stating that they had "made some appointments for Monday with some of the more attractive bidders in our recent auction. And they look forward to entering into serious discussions with those bidders in the hopes of consummating a contract in the next 10 days to two weeks."

Ordinarily, a power contract of the size and complexity that the department was seeking would involve a team of several lawyers and business people, and it would take 2 months to 6 months to negotiate the business terms of the deal and work through the complex legal problems into a final contract. A week to 10 days for even one contract was a remarkable goal. Within 6 months, however, the department had accomplished the enormous task of negotiating and executing more than 50 long-term contracts totaling 606,000 gigawatts over the next 10 years. More importantly, the vast majority of generating capacity and dollars (almost $36 billion) were under agreement in just 30 days, during the period when the contracting effort was led by the lead negotiator and energy adviser appointed by the governor to assist the department with the long-term contracts. The negotiating during that period was done in large measure by three people: the energy adviser appointed by the governor, another energy adviser under contract with the department, and an attorney from the law firm retained by the Department of General Services and the Department of Finance to assist the State on public power and energy finance issues. According to the department and its legal consultants, additional legal support was provided by attorneys from the department and the legal consultant's firm.

The negotiators clearly believed that the principal mission of the department was to sign up as much power as possible at the lowest stated price.

While no "strategy document" or "work plan" was developed during the first month, the negotiators clearly believed that the principal mission of the department was to sign up as much power as possible in as short a time as possible at the lowest stated price. When the energy adviser appointed by the governor left his position on March 2, he issued a report to the governor. In the chapter dealing with long-term contracts, the energy advisor articulated one of his goals:

> "Create a portfolio of power contracts for the "net short" needs ($^1/_3$ of total) to provide price stability and predictability and reduce reliance on spot market."

In assessing his progress toward that goal, the energy advisor focused on how much power was signed up in a one-month period:

> "The [department] deserves much credit for assisting us in a successful effort that is by far the largest concentrated cost-effective procurement of electricity ever undertaken. Forty agreements are in place. The maximum megawatts under contracts in any one-year

exceeds 10,500 megawatts. Approximately 5,000 megawatts of these supplies will be from new power plants targeted to come on-line in the next 24 months. These are complex contracts and negotiations. In the normal course of business each contract can take several months to finalize all terms. The price, quantity, and term have been agreed upon with all these suppliers and contracts are either signed or in legal review to finalize detailed terms and conditions."

In 30 Days of Work the Team Had Amassed a Significant Portfolio of Power

Within the first 30 days, the negotiating team managed to put together a large portfolio of long-term contracts and agreements in principle. Table 5 shows the number of contracts agreed to at least in principle during this period that deliver power in each year, the total capacity in megawatts, and the average price per megawatt-hour.

TABLE 5

Power Purchase Agreements Made During the First 30 Days

	2001	2002	2003	2004	2005	2006–10
Number of contracts	30	31	29	27	24	19
Total megawatts	5,582	7,769	9,671	10,642	8,992	8,742
Average price per megawatt-hour	$105	$91	$79	$73	$68	$61

Source: Progress Report on California Electricity Solutions, March 2, 2001, prepared by the negotiating team.

Note: As shown in Appendix A, the start date and term of contracts varies.

This is an unbelievable amount of power to be put under agreement in just 30 days, and to the extent that speed was the goal, the team negotiating the deals until March 2, 2001, was wildly successful.

After March 2, when the department took over the prime role with respect to the long-term contracts, the pace slowed considerably, though it was still very fast. A rough measure of the difference in pace between the energy adviser's negotiations on behalf of the department and the department's negotiations is

reflected in the average time between the parties reaching an agreement in principle and execution of a full legal contract. Before March 2, this average time was just 7½ days, while from March, when the department took over, to August, it was 73 days.

Underlying the urgency in getting the contracts signed as soon as possible was the tremendous concern about the State spending an enormous amount of General Fund money every day on loans to the electric power fund to finance power purchases on the spot market. If the generators had started delivering power under the long-term contracts the day after the contracts were executed, the concern about spot market purchases would have been addressed immediately. However, there was a significant delay between the date of signing and the date of delivery. For example, it is unclear why the State needed to move from a letter of intent to a fully executed contract in just 7 days when the power would not be delivered under the contract for another 4 months to 10 months. Delaying an additional 2 weeks to work in more detail on contract terms would not have had any effect on the timing of delivery of the power, nor would it have immediately diminished the reliance on short-term purchases in the spot market. Moreover, it is unclear whether such a delay would have delayed the decreases in spot market prices the State saw in June 2001.

It is unclear why the State needed to move from a letter of intent to a fully executed contract in just 7 days when the power would not be delivered under the contract for another 4 months to 10 months.

THE LONG-TERM CONTRACTS FALL INTO FOUR DISTINCT TIME PERIODS

During our review of the long-term Purchase and Sale of Electric Power Program (power-purchasing program), we found that its work can be divided into four critical time periods, which shaped the long-term contracts. These periods are as follows:

- **The initial period (December 2000 to January 23, 2001).** The investor-owned utilities were facing severe creditworthiness problems and by mid January the idea was developed for the department to purchase electricity under long-term contracts.

- **The intense contracting period (January 24 to March 2, 2001).** The bulk of the contracts are negotiated under the direction of the energy adviser appointed by the governor to assist the department.

- **The reassessment period (March 2 to April 1, 2001).** The department takes full control of the process of contracting and redirects its goals.

- **The department's implementation period (April 1 to August 1, 2001).** The department turns many of the energy adviser's agreements in principle into contracts but rejects others and explores new possibilities and different products.

The Initial Period: December 2000 to January 23, 2001

Beginning in December 2000 and continuing through mid-January 2001, it became increasingly apparent that the investor-owned utilities were having significant financial problems and that the department would play a role in addressing this crisis.

On January 16, 2001, AB 1X was amended and introduced the concept of authorizing the department to enter long-term contracts. Over the weekend of January 19, 2001, the department and its energy consultant developed a plan to pursue the long-term contract process. The department stated its objectives as follows:

- Obtaining an appropriate mix of product offers to provide short (30 day or less), intermediate (30 days to 1 year), and long (1 year or longer) term energy and capacity resources;

- Assuring competitive low-cost and reliable power is available to California; and

- Establishing a system that will allow a clean exit transition for the department in approximately 5 years.

In its proposed plan, the department developed an approach for accomplishing four key tasks, including plans for long-term contracts. The department projected that it needed at least a full week both to determine the energy product mix to be acquired and to structure the initial request for bids, including the development of a model or form power contract that would articulate the department's expectations for the terms and conditions of contracts. This work plan devoted significant amounts of the department's limited resources to the development of a form power contract and included a review of the terms of relevant contracts, including the ISO model contracts.

The department's plan for a fast but orderly long-term contract process was abandoned and instead the department conducted an auction for long-term power for firm energy at fixed prices, with responsive bids to be received within 27 hours of the opening of the auction. The auction was held on January 23, 2001. While many bids did not conform to the request for firm energy at fixed prices, the department was pleased to receive some bids approaching the price ranges the State had in mind. The State now had information that would permit the plan proposed by AB 1X to move forward.

The Intense Contracting Period: January 24 to March 2, 2001

On January 24, 2001, the governor appointed an energy advisor to assist the department in negotiating long-term contracts. On February 1, 2001, AB 1X became law, giving the department the necessary authority to move forward; and on February 2, 2001, the department issued a request for bids, which attached a proposed form contract.

The State's negotiators focused most of their attention in February 2001 on assuring generators that the department was a creditworthy and dependable purchaser, in order to convince them to sign any deal at all with the department. The generators were concerned that, after the department signed the contracts, the State would try to get out of the deals if they became disadvantageous. The department had limited legal resources, and it was heavily focused on drafting terms and conditions that would convince at least some of the generators that the department was creditworthy enough to do business with. There is no question that during the month of February 2001 the energy adviser's team succeeded in its effort to convince generators to sign long-term contracts with the department.

The generator can terminate the contract if the department fails to obtain the revenue requirement to pay for the power.

This hurdle was cleared in large part through the efforts of the legal consultants in drafting several key covenants that were incorporated into the standard contracts and that gave the generators reasonable assurance that they would be paid, while protecting the State's assets from exposure to the contracts. One of these covenants provides that the generator can terminate the contract, with early termination damages, if the department fails to obtain the revenue requirement to pay for the power. A second, designed to maximize the sellers' ability to be paid in the event that those revenue requirements prove insufficient, gives the suppliers' claims on the fund created by AB 1X, the Department of Water Resources Electric Power Fund (electric power fund),

priority over the claims of bondholders or the General Fund. In addition, the agreements contain well-crafted credit covenants to ensure that the State's credit is not impaired, which helps ensure that there will be a vital market for the bonds expected to be issued to populate the electric power fund. These provisions are largely responsible for the sellers' willingness to enter into contracts with the department, insofar as payment is concerned.

The decision to move rapidly significantly affected the choice and modification of the form contract. According to the department and its legal advisor:

> At the beginning of the power-purchase agreement procurement process, the negotiating team considered the use of various industry contract models. The department also considered preparing and utilizing a contract drafted specifically for the department. After consideration, in order to facilitate the solicitation, negotiation, and execution of the contracts in the time frame contemplated, the department and the negotiating team chose to use the Edison Electric Institute (EEI) model contract as the basis for the department's contracts. The negotiating team believed that it was essential that the contract form be acceptable to the largest number of bidders in light of the difficulties anticipated in convincing a sufficient number of generators to sell power to the department.
>
> The EEI model is widely accepted in the electric industry (especially in the western part of the United States) and would be familiar and acceptable to generators. The negotiating team (which included the department's legal team and other advisors) believed that using the EEI model (modified to reflect the AB 1X payment structure and other matters specific to the department) would provide commercially reasonable and adequate assurances that the department would receive the benefit of the bargain struck in the agreements and would not discourage or preclude some generators from contracting with the department.

The department apparently did not identify a need to modify the form contracts to include terms and conditions to assure reliability.

Although the contracts were modified to achieve the goal of establishing the State as a creditworthy buyer, in drafting the form contract that was included with the request for bids and that would become the starting point for negotiations, the department apparently did not identify a need to modify the form contracts to include terms and conditions to assure reliability

of delivery for a purchaser, such as the department, that is the supplier of the net short. Because the form contract was designed to promote liquid trading in a functioning wholesale electricity markets created by deregulation, they lack reliability terms seen in more traditional long-term contracts.

When electricity supply is short, terms that assure reliable physical delivery of power are essential because, unlike other commodities, electricity cannot be stored. However, the form contracts assume an environment with ample supply available at the moment it is needed and where the primary contract goal is to obligate the buyer to pay for whatever amount of power is delivered. Nonetheless, the forms the department used were not sufficiently modified to include the types of reliability terms, for example, that we saw in the department's later contracts. Consequently, the department started from a weak negotiating position by failing to inform generators in the proposed form contract that it expected certain key reliability provisions.

Indeed, some energy professionals on the panel that created the EEI model contract on which the department's draft form contract was based, reportedly recognized a utility with the responsibility of serving native load would need to modify the contract to address the absolute need for physical delivery. The native load is composed of the demand created by customers that the utility is required to serve. Nonetheless, we saw no evidence at the early stages that the negotiating team (including the department's legal consultants) ever discussed modifying the form contracts to include the reliability provisions that are found in the ISO contracts or utility contracts and some of the department's later contracts. Further, those terms and conditions are largely absent from the contracts entered into during the intense contracting period.

More than 80 percent of the power was negotiated under the urgent sense that locking electricity supply into long-term contracts as quickly as possible was crucial to calming the market.

During this period, more than 80 percent of the power ultimately purchased was negotiated in principle, if not executed in contract, under the urgent sense that locking electricity supply into long-term contracts as quickly as possible was crucial to calming the market. Whether this incredible urgency was necessary to calm the market is an open question; there is no question, however, as we explain in detail later, that the rapid contracting process minimized time for economic and legal analysis and this resulted in contracts with the terms and conditions that may not meet the reliable energy goals of AB 1X. The most significant problem created by the speed is that the contracts, particularly the early ones, lack the terms and conditions that based on our review, should be insisted on by a utility whose prime obligation is to

The rapid contracting process had a significant adverse impact on the nature of the deals and the terms and conditions of the contracts.

ensure that power will actually be delivered on a reliable basis. The most basic problem is that only a few of the contracts give the State the right to terminate them if the generator repeatedly or intentionally fails to deliver electricity as promised.

Indeed, the word "reliability" does not appear in the long-term contracts chapter of the energy adviser's report to the governor described earlier. The philosophy during this intense contracting period is perhaps best summed up in an excerpt from notes made by department staff after a conversation with the energy negotiators: "In negotiating contracts/agreements, everyone needs to realize that perfection may destroy and make processes unmanageable. Our focus should be to come out of the 'hole' as soon as possible." Clearly during this period, the department feared that slowing down and attending to details could jeopardize the State's urgent need to bring the market under control.

The Reassessment Period: March 2 Through April 1, 2001

With over 80 percent of the agreements in principle signed, the department assumed full control of long-term contracting. After the flurry of contracting in February 2001, the department took a deep breath and reassessed its position. Few agreements in principle or contracts were signed during the month of March. Instead, the department took three steps that are important from a legal perspective.

First, the department and its energy consultants carefully reviewed the contracts that had been executed and analyzed the problem provisions. The problems the department identified in those contracts were not repeated in subsequent contracts.

Second, the department more clearly defined and communicated to generators the terms and conditions it expected to see in the long-term contracts. For example, it developed a form letter of intent on March 6, 2001, that specifically listed the reliability terms and conditions the department was looking for. The department gave two seminars to generators during March and those seminars emphasized that the department was looking for provisions and terms that would assure reliability. The materials given to generators included a two-page Project Information Summary Sheet that required the generator to describe, for example, guarantees that power would be available and milestone events to monitor the construction of new generation.

Third, the department developed a process and protocol for the review and approval of both the business deals and the contracts. Persons in various areas of responsibility at the department, such as those involved in scheduling and legal matters, had to review any deal before it was executed. This check-off system ensured that the multiplicity of concerns involved in a power deal were addressed before the contract was executed.

The Department's Implementation Period: April 1 Through August 1, 2001

By the beginning of April the department had reorganized itself with new policies and procedures. The staff rolled up their sleeves and finalized the remaining deals to the extent that was possible.

Although the department performed a great deal of quality analysis on the process during this period, the remaining deals were relatively small.

What is striking about this period is that although the department performed a great deal of quality analysis on the process, the remaining deals were relatively small; that is, the effort and effect on the overall portfolio and the cost to the State were relatively minor compared to the size of the energy adviser's deals. During this period, the department had two focuses: negotiating into contracts the remaining deals the energy adviser had made before he left and finding new projects characterized by new generation and flexible pricing. Table 6 shows the megawatts placed under contract or subject to an agreement in principle, broken down by year of delivery and separated according to whether the agreements in principle were reached before or after March 2.

TABLE 6

Megawatts Placed Under Contract by the Department Before and After the Intense Contracting Period

Megawatts placed under contract based on agreements in principle reached or contract signed before March 2, 2001 (35 transactions)					
2001	**2002**	**2003**	**2004**	**2005**	**2006–10**
4,517	6,020	8,940	10,124	8,974	8,731
Megawatts placed under contract based on agreements in principle reached after March 2, 2001 (22 transactions)					
2001	**2002**	**2003**	**2004**	**2005**	**2006–10**
1,699	2,018	2,078	1,903	1,678	1,712

For those deals that had already been agreed to in principle, the department assumed that it was bound by those agreements and was left to fill in the details, thus, the basic deal, flawed or not, remained in place.

What is most noteworthy about this period is that the department spent most of its energy and resources on deals that had already been agreed to in principle by the energy adviser. The department assumed that it was bound by those agreements and was left to fill in the details; thus, the basic deal, flawed or not, remained in place. This restricted the department's ability to incorporate terms into the contracts that assured reliability and guaranteed performance. However, absent detailed analysis of the actual terms of each individual agreement in principle, the department should not have assumed that it was so bound.

Contracts Executed During the Implementation Period Better Protect the Department and the State

During the months after March 2001, the terms and conditions of the contracts improved significantly. Performance standards and reliability guarantees appeared in many of these contracts. Two different contracts with one supplier, one signed during the intense contracting period and one signed during the department's implementation period, illustrate dramatically how the terms and conditions of contracts for the same type of power improved from February to May 2001. Unfortunately, these improvements generally occurred in smaller and shorter contracts and thus have little overall impact.

For example, during the intense contracting period, the department entered into three contracts with Calpine, one of which was an approximately $2.9 billion for energy costs and capacity payments, 20-year contract for 495 megawatts of peaking capacity known as the Calpine Peaker. In May, Calpine proposed a smaller but similar deal (the Calpine SJ contract): a 3-year contract for 180 megawatts to 225 megawatts of peaking capacity. In comparing the terms, we saw that the contracts generally contained terms that better assure that the reliability goals of AB 1X will be met.

The contract proposed by Calpine in May was a mark-up of the February contract. We found that the Calpine Peaker contract, like other early contracts, does not contain the reliability and availability terms we believe are necessary for the department to assure that it will always be able to perform its unique role as purchaser of the volatile net short.

The five problems we identified in the proposed contract are (1) it would allow Calpine to substitute power from other sources, which the department appeared to resist in later contracts that included new generation; (2) it lacked prudent industry practice

requirements as to operation and maintenance; (3) it had no availability standards; (4) except for the first year, it did not clearly link reductions in capacity payments for new generation for failure to construct in a timely manner or failure to operate; and (5) it did not provide the department with the ability to terminate the contract for force majeure or failure to operate for a period of time.

Based on our review of the negotiating history of the February Calpine Peaker contract, we found no evidence that the negotiating team ever asked Calpine in February for any of the five terms we view as omissions but that the department was successful in including in the later Calpine SJ agreement. While it is unclear whether Calpine would have agreed to most of those terms in February if the department had asked; Calpine did agree to most of those terms in the later Calpine SJ contract when asked. In addition, we know that other bidders proposing similar projects in February offered availability guarantees and conditioned capacity payments on performance, as discussed in detail later in the chapter. Although these other proposals did not result in contracts for legitimate business reasons, they demonstrate that some generators assumed that the department would be looking for reliability guarantees. Because more than 20 percent of the power under contract to the department is with Calpine, the negotiation of the terms and conditions of those contracts, particularly the large contracts executed in February, merit additional scrutiny. Appendix B discusses these contracts in more detail.

In addition, the earlier Calpine contract permits the seller to substitute power from other power plants, while the later one does not. To the extent that the goal of the State in the earlier contract was to give Calpine beneficial terms, partly in consideration for the seller increasing the California energy supply, the State may have deprived itself of the benefit of that bargain if the contract is read to permit the seller to fulfill the contract out of existing energy supplies in the market.

We asked the department whether advice from their legal consultants had prompted it to seek the improved reliability terms we saw in the later contracts. While the department received legal advice from its legal consultants on the Calpine contracts, just as it had on the other long-term contracts, the department asserted attorney-client privilege as to the contents of any privileged communications it received from its legal consultants on long-term contracts.

THE LONG-TERM POWER-PURCHASE CONTRACTS MAY NOT ALWAYS ENSURE THAT POWER WILL BE DELIVERED WHEN WANTED EXCEPT BY CONFERRING SUBSTANTIAL BENEFITS ON SELLERS FOR DELIVERY

In our legal review of the long-term power-purchase contracts, we measured the department's long-term power-purchase contracts against AB 1X's purpose: to ensure a reliable source of energy at the lowest possible price. The question we asked was, to what extent do the contracts assure that power will actually be delivered when and where it is requested in the requested amounts, and to what extent do they assure that sellers will build and maintain the generating capacity necessary to fulfill the contracts? The answer that we found is that sellers' profit stability is the primary method used to promote the State's goals; more effective terms, that based on our review are better suited to the needs of a buyer with the obligation to supply the net short, are absent from the majority of the contracts.

Terms, better suited to the needs of a buyer with the obligations to supply the net short, are absent from the majority of the contracts.

An In-Depth Analysis of 19 Transactions Plus a Limited Review of the Remaining Contracts Led to Our Findings

A legal review of the terms of the power-purchase agreements was performed in stages and in varying levels of detail. We developed a representative sample of the agreements for in-depth review and analysis (the audit sample). The audit sample consisted of the contracts the department entered into with Dynegy, Coral, Calpine, Allegheny, and Sempra, which accounted for 19 separate transactions between the department and these suppliers. The sellers reflected in the audit sample contracts are all among the eight largest suppliers of power to the department, and the contracts in the audit sample cumulatively account for approximately $26 billion and 367,000 gigawatt-hours, amounting to more than 61 percent of the total gigawatt-hours purchased by the department.

The bulk of the remaining contracts were "graded" using a report card consisting of the categories we deemed most relevant to our analysis of whether the contracts secure reliable power for the department. Appendix C contains the results of this grading process. During this process, our review was limited to screening the contracts for the characteristics that we found to be problematic in our detailed analysis of the audit sample contracts. As such, the grades we attach to each contract refer only to those characteristics, reflecting the comparatively little time spent grading each contract. To fully assess how well the graded contracts

protect the department's interests, it would be necessary to perform an in-depth review similar to the review we performed for the contracts in the audit sample. Our findings reflect the results of both analyses.

The Five Types of Contract Provisions Typically Used to Ensure a Seller's Performance Have Varying Levels of Effectiveness

Five kinds of provisions are commonly used in long-term power purchase contracts to increase assurance that the seller will render performance: (1) provide sellers with such favorable terms (a high price, lenient delivery and availability standards, credit assurances, and so on) for ordinary performance that they will deliver power in order to collect the payments; (2) provide cover damages that obligate the seller to pay the buyer the difference between the contract price and the market price of power that the buyer is forced to purchase to replace power that the seller fails to deliver; (3) provide sellers with monetary rewards or penalties for performance outside specified limits, such as bonus payments for early completion of new generation or for superior availability or penalties for delayed completion or lack of availability; (4) provide buyers with practical rights to coerce sellers to deliver power or to build and maintain generation, including the ability to inspect premises in order to monitor construction progress, plant performance, or the reason for unscheduled outages; and (5) provide the right to terminate for repeated failure to perform.

Cover damages, which the long-term contracts provide for, are not a bad remedy; in fact, they are particularly good as a guarantee of reliability of price, if substitute sources of supply are available when the seller fails to deliver. But cover damages are not particularly good for ensuring reliability of physical delivery of electricity to a purchaser that is the supplier of the net short in an unstable market with a very tight power supply. To some extent, a seller's obligation to pay cover damages minimizes its financial incentives not to deliver to the department in rising markets because, in theory at least, the seller will have to pay the department any excess profits it earns by diverting power to a buyer willing to pay the current market price. The theory works, however, only in stable markets where there is adequate replacement supply and where sellers cannot manipulate the markets. This was not true for the department, which was contracting in the face of colossal market failures. Moreover, the protection works best for buyers whose only risk is financial—that is, those that trade in energy for profit.

In an unstable market with very tight power supply, cover damages are not particularly good for ensuring reliability of physical delivery.

The best means of ensuring delivery is to make the repeated or intentional failure to deliver an event of default by the seller.

Among the remaining provisions used to ensure reliability outlined earlier, some are more effective than others from the buyer's perspective. If contractually possible, the best means of ensuring delivery is to make the repeated or intentional failure to deliver an event of default by the seller, which gives the department the right to terminate the contract and to collect damages. Given the long-term nature of the deals under review, this provision would have been the best means to ensure performance. Sellers do not want their rights terminated and, as a result, will take all reasonable actions to fulfill their end of the bargain.

Providing significant penalties for failure to deliver can be useful for the buyer because they provide the buyer with significant leverage to force seller performance. Next best for the buyer are terms that create incentives for superior performance. Even though the buyer pays for the incentive, the buyer also receives the benefits of the superior performance (such as enhanced availability and better operating performance).

Further down the scale of measures that will ensure reliability are inspection rights and similar buyer remedies to evaluate actual operation. While these types of provisions can be coupled with other provisions to provide "teeth" to the remedy, by themselves they tend to be somewhat subjective and difficult to enforce. This being said, however, in situations such as the one California was experiencing during this period (in which generators were accused of manipulating the market by withholding generation), such provisions can help ensure seller performance.

The least favorable seller incentive is to provide terms so favorable that the seller wants to perform. This method is less preferable because the buyer receives nothing extra for agreeing to seller-friendly terms; in other words, extraordinary terms are exchanged for ordinary performance by the seller.

The Contracts We Reviewed May Not Always Provide the Department With Effective Tools to Assure That the Sellers Deliver Power

A range of provisions was potentially available to the department to give it some measure of practical control in cases of persistent or repeated failures by sellers to build generation or deliver power. The most buyer-friendly terms would be ones that gave the department the right to take physical control of the seller's premises—for example, the right to take over a delayed construction job or to physically bring on-line a shut-down facility. The

contracts do not contain such provisions, but this in itself is not alarming: It is not clear that the department has the legal or practical ability to run or build a generating plant. However, similar provisions are not unheard of in favor of buyers like the department that are providers of the net short for retail load and, indeed, as we explain later, the department has the option in certain contracts to purchase the new generation after the term of the contract expires.

One provision that we might have expected to see in the contract is the department's right to inspect any unit having an unscheduled outage.

One provision that we might have expected to see is the contract right to inspect any unit having an unscheduled outage, in order to confirm that the outage was due to a genuine operating failure. This provision would be valuable if the State suspected that generators were seeking to drive up prices by withholding generation. The long-term contracts generally do not contain such provisions.

The lack of such provisions is striking in the California context. There were deep suspicions at the time that sellers were deliberately withholding power in an effort to manipulate market prices. The governor was stepping up inspection and enforcement by the CPUC and was recommending criminal penalties for such deliberate withholding. On the contracts front, however, the department was not taking equivalent punitive or coercive measures to ensure that sellers would deliver the power they were promising to deliver.

Some of the later contracts contain more provisions to ensure the seller's performance. For example, the Coral agreement requires Coral to provide reports on its units' progress toward commercial operation. Although this provision does not expressly give the department a right to control Coral's performance, it may provide it some practical ability to remove obstacles to Coral's performance. For example, if commercial operations were being impaired due to delays in obtaining permits required for the construction or operation of the Coral units, the department would have the opportunity to assist Coral in an effort to get the obstacle removed. In contrast to the Coral provisions, many of the contracts actually make sellers' delivery obligations contingent on the newly constructed generation being commercially available to supply power without any such protection for the department.

Similarly, the Calpine SJ contract gives the department the right to have Calpine's units performance tested twice per year. This provision not only assures the department that it will not be

making payments for capacity that is not in fact available, it also allows the department to identify potential performance problems early on and to work with Calpine toward their resolution.

The Contracts Generally Require Payment of Cover Damages for Failure to Deliver, but Not a Right to Terminate for Repeated or Intentional Failures to Deliver

All of the long-term contracts we reviewed including contracts for both unit contingent and firm liquidated damages products, require suppliers to pay cover damages for failure to deliver power. Cover damages, however, do not provide particularly good protection for a buyer serving as a public utility with the obligation to cover the net short. For example, suppose that the contract price for power is 6 cents per kilowatt-hour and that, during a stage 3 emergency, the price in the real-time market rises to 60 cents per kilowatt-hour. If a generator fails to deliver for 6 hours during that stage 3 emergency, the cover damages would be 54 cents per kilowatt-hour—the difference between what the State had to pay in the market, 60 cents, and the contract price, 6 cents. That 54 cents per kilowatt-hour for the 6 hours of power that were not delivered is the department's sole remedy, regardless of how much the withholding of power during that critical time hurt the department's overall obligations or whether the generator deliberately withheld the power to manipulate the market.

"If utilities have to have the physical power, for example to serve native load, a cover damages remedy may not be satisfactory."

If the department were simply a trader in a well-functioning deregulated wholesale electricity market, cover damages might suffice; however, for an entity in the department's position, responsible for buying the net short in an unstable market, cover damages do not provide an adequate remedy, nor are they the ideal weapon for ensuring that suppliers deliver at critical times. The department's contracts are based on an industry-standard model contract primarily designed for trading in a functioning deregulated wholesale electricity market (discussed later in this chapter), the drafters of which have stated since early 2000 that, "If utilities have to have the physical power, for example, to serve native load, a cover damages remedy may not be satisfactory."

Cover damages may not be an adequate remedy for the department because they may not remedy all of the harm that the department would suffer from the kind of gamesmanship that allegedly occurred in 2000. For example, suppose that a generator withheld 500 megawatts of contracted power on a particular day

during a stage 3 emergency. Suppose further that the department already needed to buy 1,000 megawatts in the real-time market that day. The generator's failure to deliver would push the department's total purchases in that market to 1,500 megawatts, and the department's demand for an additional 500 megawatts would push up the entire market price. Thus, the department would pay more for the entire 1,500 megawatts, not just for the 500 megawatts that was withheld. This is exactly the type of market manipulation that state and federal regulators were studying when AB 1X was enacted. Although cover damages would replace the cost of the power that was actually withheld, they would not take into consideration the effect that the failure to deliver would have on the market as a whole and on the other purchases the department must make to serve the net short.

Just as cover damages may be an inadequate remedy for all of the harm the department might suffer, they may be an inadequate threat to prevent sellers from failing to deliver. For example, a seller might realize gains on other sales that more than make up for the cost of paying cover damages to the department. In fact, cover damages in themselves provide sellers no economic incentives to perform in any situation in which the cost of providing power to the department exceeds the cover damages the seller would owe for failing to deliver. In the scenario just discussed, for example, a seller would lose profits in the real-time markets if it did not withhold its power. Since those costs exceed the cost of the cover damages, the seller may choose to withhold power from the department.

Termination rights overcome some of the shortcomings in cover damages by increasing the cost to the seller of not delivering to the department.

Another possibility is that the seller might have to incur extraordinary costs to deliver power to the department during an emergency. For example, a seller might be forced to incur significant overtime and repair costs in order to stay on-line with the generation necessary to deliver power during a crisis period. If those repair costs exceed the cover damages that the seller would owe for failing to deliver, it would have little incentive to deliver. However, if faced with the cost of losing a lucrative long-term contract, the generator would have much more incentive to keep its generation on-line. Therefore, the termination right is far more effective than cover damages in motivating the supplier to pull out all the stops to deliver those 6 hours of power.

Finally, the provision for cover damages assumes that an adequate supply of power is available to replace the power that the generator did not deliver. However, one of the problems during California's last crisis was that the demand for power was greater

than the supply. If a generator withholds power during another period of short supply, the department may not be able to replace it. The ability to collect cover damages does not sufficiently assure the department of an uninterrupted supply of power. Cover damages, which compensate for the loss only of a particular delivery, regardless of its timing or how serious the consequences, may prove to be an ineffective remedy for the department nor enough of a threat to sellers to meet the needs of an entity in the department's unique role of purchaser of the power necessary to fill the net short.

A provision that is generally lacking in the long-term power-purchase contracts is the right to terminate the contracts in the face of repeated, persistent, or intentional failures by sellers to deliver promised power.

In contrast, the right to terminate for repeated or intentional failure to deliver could have provided the department with a more effective tool to ensure performance. In the majority of the long-term contracts the department does not have the right to terminate the contracts in the face of repeated, persistent, or intentional failures by sellers to deliver promised power or to construct promised generation. A right of termination is particularly important to the department for two reasons. First, in a long-term contract that promises a lengthy, reliable payment stream to sellers, the threat of termination is a particularly effective tool for assuring performance. Second, the right of termination is necessary to make sure that the department receives the full benefit of the long-term contracts.

Without a termination right, the department has no remedy for the harm of having to continue to deal with an unreliable generator for the next 5 years to 10 years. When failure to deliver is not an event of default, the department cannot get rid of a generator that is performing poorly and replace it with a more reliable supplier. Instead, the department is locked into a relationship with an undependable supplier for the remaining years of the contract and generally for hundreds of millions of dollars.

The department bargained for immediate relief from the intolerably high spot market prices it was paying in the winter of 2000-2001 and for an increase in the overall energy supply for California. In exchange, it offered sellers long-term commitments to pay what likely would be above-market prices in the later years of the contract. If sellers fail to deliver in the early years—especially if they aggressively seek to enforce excuses for nonperformance—the department might very well be left with its obligation to pay lucrative prices over the long term without having received the immediate benefit it was bargaining for. In contrast, if faced with the cost of losing a lucrative long-term contract, the seller would have more incentive to keep generation on-line even

when faced with costly repairs. Likewise, a seller is less likely to fail to deliver power to obtain a short-term profit if doing so could result in it losing a lucrative long-term contract. Given the way the pricing of the contracts is structured, the department would have benefited greatly from a right to terminate in such situations.

Another way the department could have strengthened the cover damage remedy would have been to include financial penalties for repeated or intentional failure to deliver. However, under most of the contracts, sellers are not subject to any additional financial penalties under those circumstances.

The Contracts, Particularly Those Entered Into Early in the Process, Contain Virtually No Penalties for Failure to Build New Generation

The contracts based on new generation do not expressly provide that failure to build the generation is an event of default.

Many of the department's long-term purchase contracts contemplate the building of new generation to supply the power being contracted for. Although the long-term contracts typically permit the department to declare a default if the seller fails to perform any "material covenant or obligation," the contracts based on new generation neither expressly provide that failure to build the generation is an event of default, nor do they expressly make the building of the new generation a material covenant or obligation of the seller.

The long-term contracts for new generation typically do not impose the substantial penalty of termination for failure to build such generation, but some of the later contracts that call for new generation do provide penalties or disincentives for sellers' failure to build. For example, the Coral contract requires the seller to pay the department a $5 million penalty for canceling contract quantities based on the inability to develop additional generation, unless the inability is caused by legal changes in the seller's environmental obligations or by the seller's failure to obtain permits despite diligent effort. In addition, the contract sets target dates for bringing plants into commercial operation and gives the department the option to reduce contract quantities from (and capacity payments attributable to) units that have unjustified delays in achieving commercial operation.

The fourth Calpine contract (executed in June) is similar to the Coral contract in this regard. It anticipates delivery of power from four units to be built. The contract sets target dates for

commercial operation to begin; if commercial operation is not achieved, the department has the right to terminate the contract with respect to the unit or units that have not begun commercial operation. Moreover, a substantial portion of the contract price consists of capacity payments, which are reduced on a pro rata basis if some of the designated capacity is not actually available.

In Some Cases, the Contracts Provide Disincentives to Deliver Power or to Build New Generation

Substantial, front-loaded payments from buyer to seller that are not refundable in cases of subsequent nonperformance by the seller can provide sellers with disincentives to perform. If a seller has been paid and is not required to refund the payment for failure to deliver, only a sense of moral obligation will make the seller incur the cost of delivering power. A prime example of such disincentive to perform is found in the 20-year peaking capacity contract with Calpine. That contract calls for 495 megawatts of power to be delivered from 11 plants, each with a capacity of 45 megawatts. The power, to be scheduled by the department, consists of up to 2,000 hours per year during specified peak periods.

The department pays $73 per megawatt-hour for the power that it actually schedules; in addition, the department makes annual capacity payments of $90 million per year for the first 5 years (prorated in the first year) and $80 million per year for each of the remaining 15 years. During the first year, when the 11 units are all apparently anticipated to come into commercial operation, the capacity payment is paid monthly and prorated during months when fewer than 11 units are in operation. After the first year, there is no provision that expressly makes the additional payment for capacity contingent upon the actual availability of the units designated in the contract. In other words, for the remaining 19 years of the contract, there is legal risk that Calpine could attempt to assert that it is entitled to receive the annual capacity payments even if the designated units are not on-line. Thus, the department is exposed to the risk that Calpine could demand that the department pay $1.56 billion in exchange for little or no new generation. According to the department, the risk that it would actually be required to make such a payment is low.

The department is exposed to the risk that, at Calpine's option, they will be obliged to pay $1.56 billion in exchange for little or no new generation.

Through Risk-Shifting Provisions, the Contracts We Reviewed Provide Stable, Long-Term Profits for Suppliers

Consistent with the goals of AB 1X, buyers of power want a reliable supply at the lowest possible price, as well as price stability. By contrast, sellers generally desire a low cost of service risk and the highest possible price. Thus, if we view contracts on a spectrum ranging from the most buyer-friendly to the most seller-friendly, contracts at the buyer-friendly end of the spectrum would contain reliability guarantees and price stability (few if any of the terms would allow the price to escalate if the seller's costs increase). At the seller-friendly end of the spectrum, the contracts would contain a high-base price, a lengthy term, cost of service pass-throughs, broad termination rights for the seller, and minimal termination rights for the purchaser. One would expect contract terms to vary depending on the importance of these goals; for example, if securing reliable power is paramount to the buyer, the contract can be worded to enhance reliability, through penalties for failure to deliver and/or incentives to encourage seller performance. Whether the buyer uses penalties, incentives, or a combination of both to secure reliable delivery of power, in a seller's market (that is, a market in which demand exceeds supply), it is reasonable to expect that in exchange for reliability, sellers will obtain favorable price and/or cost stability terms.

The department's long-term contracts use incentives for performance rather than penalties or coercive remedies for nonperformance to ensure delivery of power and building and maintenance of generation.

Generally speaking, the department's long-term contracts use incentives for performance rather than penalties or coercive remedies for nonperformance to ensure the delivery of power and the building and maintenance of generation. These incentives are limited to lucrative terms for ordinary performance, such as (1) long-term, high-megawatt contracts that provide sellers with significant long-term income, (2) favorable price terms for the seller, (3) reduced risk associated with rising generation and delivery costs, and (4) enhanced seller termination rights. Very few of the contracts provide incentives for superior performance—such as early completion of construction of new generation—even though in the early months of 2001, there was significant concern that existing generating capacity would not be sufficient to meet the State's power demands that summer.

The Long-Term Contracts We Examined Ensure Revenue Stability for the Suppliers

Table 7 shows the duration and size of the power purchase contracts with the six largest suppliers of contracted power. The magnitude and length of these contracts, combined with the department's relative inability to terminate them, results in a very stable, significant, and long-term income stream for the sellers. The figures in this table reflect only the first 10 years of power and power costs for the contracts. The table is intended to illustrate only the large quantity of power and large dollar value of these contracts. It is not intended to provide a comparison of the pricing of these contracts because it does not account for differences in the type of power delivered (such as peak, off-peak, or base load) or that certain of the contracts (for example, Coral) are tolling agreements, the ultimate cost of which depend upon the price of gas. Also, as we explain in more detail below, these figures represent the best-case scenario (that is, full performance by the seller and no triggering of, for example, price escalators).

TABLE 7

Duration and Size of the Contracts With the Six Largest Suppliers of Contracted Power

Seller	Contract Duration*	Total Gigawatt-Hours	Total Contract Base Price (In Billions)
Calpine	3-20 years	145,700	$9.770
Sempra	10 years	93,300	6.238
Allegheny	1-10 years	63,900	3.909
Williams	5-10 years	56,500	3.779
High Desert	8 years	51,900	3.010
Coral	10-11 years	28,700	2.293

* Approximate.

The income derived from these contracts provides the basic incentive for the sellers to perform under the contracts and deliver the power contemplated by the agreements.

Many of the Long-Term Contracts We Examined Shift Risks and Costs to the Department

Beyond long-term revenue stability for the sellers, many of the contracts also contain provisions that ensure stability for the sellers' cost of generating the power. The form power contracts on which the department based its request for bids generally assign to the seller the risks and costs associated with generating and delivering the power up to the delivery point, whereupon the buyer assumes any further costs and risks. Many of the department's contracts, however, shift varying degrees of these pre-delivery-point risks and costs away from the sellers and onto the department.

For example, the contracts commonly require the department to pay for any new taxes that California may levy that affect the generation or delivery of power. Others go further and require the department to reimburse the seller for any new taxes imposed by any entity, including the federal government, as well as for charges imposed by any federal agency, including FERC. Some of the contracts require the department to pay for any emissions charges or environmental upgrade costs the seller incurs as a result of generating power for the department. The Dynegy contracts, for example, require the department to supply Dynegy with energy if supplying the department restricts Dynegy's ability to serve its other purchasers during, or even after, the term of the contracts. When you consider that the purpose of AB 1X is to increase supply and to meet the net short, the concept of requiring the department to supply Dynegy with energy is surprising. The Calpine contracts go further still and increase the contract price if any governmental action results in an increase in Calpine's cost of service greater than 50 cents per megawatt-hour. The Williams contracts contain a similar provision, with no threshold for costs resulting from California government action but a $5 per megawatt-hour threshold for costs other than those arising from governmental action.

The Dynegy contracts require the department to supply Dynegy with energy if supplying the department restricts Dynegy's ability to serve its other purchasers during, or even after, the term of the contracts.

While these provisions are favorable to sellers and thus may promote delivery of power and construction of new generation, they create significant contract management problems for the department and the risk of exposure to future price volatility as sellers seek to pass increasing costs on to the department. Some of the most troubling provisions in this regard are discussed in greater detail in Appendix B.

The Long-Term Contracts Assure the Sellers of the Department's Creditworthiness

In addition to cost (and thus profit) stabilizers, the contracts also contain mechanisms to ensure that sellers will actually receive the contract payments. The sellers are given bond and creditworthiness assurances, are not bound to continue delivering power if the electric power fund from which the department makes payments under the contracts contains inadequate funds for that purpose, and may terminate the contract if the department fails to make any payment.

The Long-Term Contracts Are Seller-Friendly With Respect to Nondelivery

Unit firm contracts are less reliable from an energy delivery standpoint than contracts for firm energy with liquidated damages.

The contracts are also generally seller-friendly in their delivery requirements. The department's energy portfolio contains two general types of contracts for the purchase of firm energy: unit contingent contracts, which excuse failure to deliver from the specified unit for forced outages or unanticipated events, and firm energy with liquidated damages (firm LD contracts), which excuse failure to deliver from the specified unit for narrowly defined force majeure events. Unit contingent contracts are, by their nature, less reliable from an energy delivery standpoint than firm LD contracts, because unit contingent contracts excuse delivery altogether for various reasons with no damages owed to the purchaser. It is entirely appropriate to assemble an energy portfolio containing contracts for different products (such as firm LD, unit contingent, dispatchable, as available, and so on). However, given the department's unique role in assuring reliability—in which delivery of the energy is paramount and price, while important, is secondary—a firm product with meaningful liquidated damages better assures seller performance.

Many of the department's contracts are for unit contingent products rather than firm LD products. The flexibility inherent in unit contingent products is essentially another favorable provision for the sellers and decreases the likelihood that a seller will actively seek to exercise its option to terminate the contract as a whole.

As we discuss later, the same provisions that act as incentives for the sellers (revenue stability, cost increase reimbursement, broad seller termination rights, and limited purchaser termination

rights) also create significant and long-lasting dollar exposure for the department and the State well beyond the contract base price for power.

The Sellers Have Broad Rights to Terminate the Contracts by Declaring an Event of Default

The contracts may be terminated upon the declaration of an "event of default." In general, in contracts, an event of default clause typically gives the declaring party, whether the seller or the buyer, the right to terminate the contract and to collect a termination payment. Under the contracts we reviewed, the disparity between the seller's broad rights to declare an event of default and the department's practical inability to declare an event of default and terminate for any reason is striking. This disparity has a significant practical effect on the parties' respective ability to "force" performance under the contracts because along with the power to declare a default comes the ability to accelerate the payments owed for the entire term of the contract and to suspend the nondefaulter's performance under the contract immediately. As we explain in more detail later, a declaration of an event of default by a seller in one of the longer-term agreements (such as Calpine) could result in an immediate payment obligation of more than $1.8 billion from the department.

The disparity between the seller's broad rights to declare an event of default and the department's practical inability to declare an event of default and terminate for any reason is striking.

The Department, Particularly in the Early Contracts, Has Few if Any Rights to Declare an Event of Default

As explained earlier, in the vast majority of the contracts, the seller's repeated or intentional failure to deliver power to the department is not considered an event of default.

In addition, certain contracts (particularly those for which the agreement in principle was reached in February or early March 2001) do not contain provisions allowing the department to declare an event of default and terminate the contract for failure to construct agreed upon generation. Contracts based on future development of new generation should provide a schedule for completing construction milestones, reporting requirements to keep the purchaser advised of the progress toward meeting those milestones, penalties for failure to meet milestone deadlines, assurances that the seller has the financial backing to develop the new generation, and penalties (including the right to take over the project or terminate the contract) should that financial backing become insufficient. Contracts entered into

after the intense contracting period generally contain more protection for the department in this regard than those agreed to earlier on in the process.

A comparison between the Coral and Sempra contracts illustrates the differences in protection for the department. The Sempra contracts (for which an agreement in principle was reached on February 28, 2001) contemplate the construction of significant new generation but contain no provision for the department to monitor Sempra's financial condition, much less terminate the contracts should Sempra lose the financial wherewithal to complete the projects. By contrast, the Coral contracts (for which an agreement in principle was reached on March 16, 2001, and which were executed in May 2001) also contemplate construction of new generation but contain target dates for reaching certain milestones in the construction process and penalties for failure to achieve commercial operation of the units. They also provide the department with the ability to review Coral's financial status and the option of terminating the contract if the credit rating of Coral's financial guarantor falls below a reasonable level.

The Sellers Have Broad Rights to Declare an Event of Default

The sellers have fairly expansive rights to declare an event of default. They can do so if the department fails to (1) comply with any "material" provision of the contract ("materiality" is not defined), (2) make any payment due under the contract after written notice, or (3) satisfy the creditworthiness requirements of the contract. It is noteworthy that the seller can terminate the contract if the bonds are not issued by a particular date, but the seller is not entitled to a termination payment in those circumstances.

The Financial Consequences of a Large Seller Declaring an Event of Default Would Be Significant

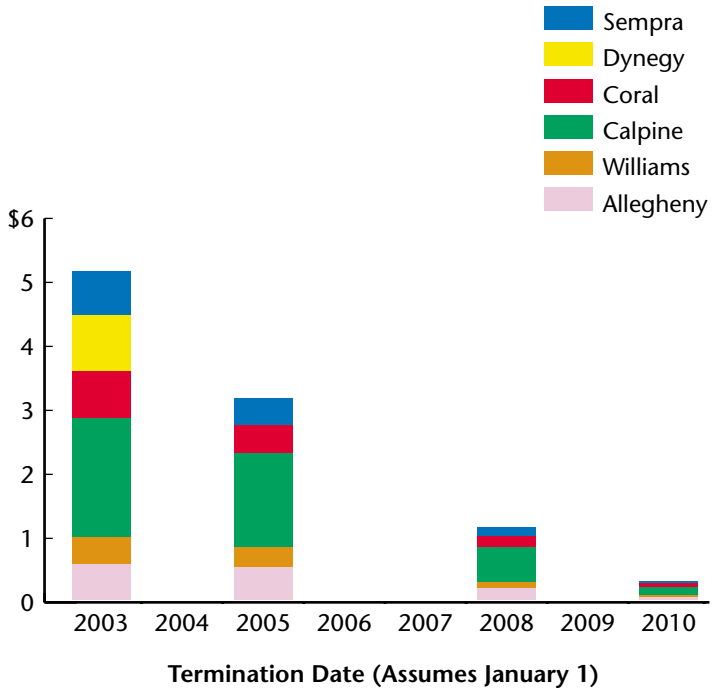
If Calpine were to successfully declare an event of default in January 2003, the termination payment owed by the department would exceed $1.8 billion.

If a seller declares an event of default, in addition to suspending performance under the contract, the seller is entitled to a termination payment. The methods used to calculate the termination payments are generally consistent among the contracts: the nondefaulting party is entitled to the present value of the positive difference between all of the payments that would have been due for the life of the contract plus termination costs and the price the seller receives under a replacement contract. For example, if Calpine were to declare an event of

default in January 2003, the termination payment owed by the department would exceed $1.8 billion. Figure 7 shows the potential termination payments for the six largest contracted suppliers for selected years.

FIGURE 7

Potential Contract Termination Costs (In Billions)



Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

In addition to creating an immediate obligation to make this significant payment, a declaration of an event of default by a large seller such as Calpine could create a spiral of defaults in the remaining contracts. The contracts contain provisions requiring the department to make all payments to the sellers as well as to ensure that the electric power fund has sufficient assets to meet all of the obligations the department has under all of the contracts with the sellers. Moreover, at least one of the contracts, in addition to requiring the department to request a revenue requirement sufficient to meet all obligations, grants the seller the power to seek an injunction from a court requiring specific performance of this duty.

If funds are not available in the electric power fund, a seller cannot force the department to make payments on the contracts from another source.

Although as we noted earlier, some of the contracts contain price escalators that could significantly increase the base price that the department agreed to pay for power, the department's overall exposure for its contractual obligations is limited to the amounts actually available in the electric power fund. In other words, if the amount needed is not available in the electric power fund, a seller cannot force the department to make payments on the contracts from another source. Unless the department anticipates an event of default when requesting its annual revenue requirement, making a large termination payment (such as $1.8 billion to Calpine) could result in the electric power fund containing insufficient amounts for the department to meet its payment obligations. If not remedied within 180 days (either through an increase in rates or other influx of funds), other unpaid sellers would have the right to declare an event of default.

In Certain Circumstances, the Department May Benefit by the Seller Declaring an Event of Default

Despite the early payout obligation just mentioned, the declaration of an event of default could, in certain circumstances, benefit the department. Many of the contracts contain cost pass-throughs for "governmental charges" (such as new taxes or other governmental actions adversely affecting the sellers' cost of service), environmental upgrades, and emissions charges resulting from the seller generating power for the department. In perhaps the most extreme example of an uncapped energy price, Calpine is entitled to an increase in the contract price if its cost of service (apparently as that figure is calculated by Calpine) increases by more than 50 cents per megawatt-hour in the aggregate over the life of the contract. A declaration of an event of default would eliminate continued exposure for these costs in the applicable contract and, depending on the market price for power at the time of the declaration of default, may permit the department to exit one or more of the most costly contracts at relatively little added cost.

The concept of the termination payment is that the seller should be made whole; that is, the seller is entitled to the present value of the payments it would have received from the department if the contract had terminated by its own terms at the end of the contract period. If, for example, the contract rate is 7 cents per kilowatt-hour and the replacement contract price (based on the market rate for energy projected at the time of the termination) is 5 cents, the department is responsible for paying the seller the

difference—in other words, 2 cents times the number of kilowatt-hours that would have been delivered under the contract, plus the costs incurred by the seller related to the termination.

Assuming that other potential sellers exist in the market from which the department can purchase power, the department would then obtain a replacement contract, presumably for at or around the market rate—5 cents per kilowatt-hour in our example. Thus, the department's total price for the replacement power would be roughly the same as the original contract price (the 5 cents per kilowatt-hour paid to the replacement supplier plus the 2 cents per kilowatt-hour termination payment paid to the original replaced supplier). The actual difference in the department's potential exposure under the new contract, however, could be very significant if the department were able to negotiate better terms with the new supplier. Therefore, although the base contract price would remain at or around the original level, the overall dollar exposure could be reduced if better contract terms were attainable due to a more favorable climate for power purchasers (that is, a market in which demand does not exceed supply, as is projected for California starting in 2005).

Another scenario in which the department may benefit from a declaration of an event of default by the seller is if it finds that it has purchased too much power—that is, if the supply exceeds the demand. If, for example, in 2005 the department determines that it has significant excess power from these contracts, it could, rather than continuing to pay 7 cents per kilowatt-hour for the life of a contract for power that it does not need, seek to "buy" its way out of the contract for 2 cents per kilowatt-hour through a default, thereby potentially significantly reducing the overall dollar cost of the contract. In other words, depending on market price and supply conditions, the department may be better off if a seller in a contract with high potential exposure (such as Calpine, Dynegy, or Williams) gives notice of a default and the department pays the termination payment rather than living with the contract for the full term.

Although the department is free to take actions that would constitute a default of the contract, declaring a default is the seller's decision.

An impediment to such an exit strategy, however, is that the contracts in most cases do not give the department the choice of declaring a default or even provide that certain conduct is automatically a default (thereby allowing the department to "force" a default). Instead, although the department is free to take actions that would constitute a default of the contract, declaring a default is the seller's decision.

THE FORM CONTRACTS INCLUDED IN THE REQUEST FOR BIDS LACKED IMPORTANT RELIABILITY PROVISIONS, CAUSING NEGOTIATIONS TO BEGIN FROM AN UNNECESSARILY WEAK POSITION

One of the reasons that the contracts lack the usual reliability terms one would expect from a buyer in the department's position is that the form contract the department used at the beginning of the contracting period was seller-friendly, one primarily designed to promote liquid trading in a well-functioning deregulated wholesale electricity market. As such, it lacked the reliability terms that were important to ensure reliable delivery of power for the department. The starting point for the State's negotiations of the terms and conditions of the contracts with the generators was the form contract attached to the request for bids issued on February 2, 2001. A few weeks later, the department developed another model contract that was different in structure but very similar in substance for use in negotiating the terms of the contracts with generators. Both of these form agreements treat a contract for the sale of electricity as a financial commodities transaction on the wholesale electricity market rather than focusing on reliability of physical supply of electricity in an unstable market.

We believe the contract forms required modification to best serve the department's unique role as purchaser of the net short in a deregulated market that was no longer competitive.

In view of the primary intended use of the form contracts, we believe the contract forms required modification to best serve the department's unique role as purchaser of the net short for California in a deregulated market that was no longer competitive. We cannot say with certainty that if certain terms assuring reliability had been included in the form contracts, they necessarily would have been included in the executed agreements. It may well be that the suppliers possessed superior leverage and would have bargained these provisions out of the final agreements. Nonetheless, according to the department when entering into the early but largest contracts, the negotiating team, including its legal consultants, determined that the form contract adequately protected the department. Based on our review, the department appears never to have asked suppliers for provisions that would better ensure reliable physical delivery of power until later in the contracting process. Consequently, we cannot ascertain whether, and at what cost, such additional rights to protect reliability could have been achieved.

When contemplating multiple business transactions with different parties, it is common practice to develop a standard contract to be used as the starting point for negotiations. The use of a standard contract has three major purposes:

- It brings some degree of uniformity to similar arrangements.
- It informs the parties on the other side of the basic terms desired.
- It provides a checklist of terms to ensure that key terms are included in individual agreements.

When the buyer provides the initial contract, as was the case here, sellers' expectations will be set by the terms and conditions contained in the buyer's proposal; indeed, sellers will perceive that the buyer has proposed buyer-friendly terms and will work to shift the balance in their own favor. To work well as an "opening bid" or a subsequent checklist, a buyer-proposed form contract must therefore contain, at a bare minimum, all of the buyer-friendly terms that will be needed in the final agreements.

The department proposed a seller-friendly contract that omitted the reliability terms that were important to ensure reliable delivery of power.

The department's form contracts did not meet the goal of developing a buyer-friendly opening bid. Instead it proposed a seller-friendly contract that omitted the reliability terms that were important to ensure reliable delivery of power for the department.

The Contracts From Which the Form Contracts Were Developed May Not Assure Reliability of Delivery to an Entity That Has to Fill the Net Short

At the time AB 1X was being enacted, two form contracts were employed in California. One was developed by the Western Systems Power Pool (power pool), and the EEI was developed by the Edison Electric Institute and the National Energy Marketers. The power pool agreement had been in place for some time in the West. Indeed, the department was a signatory to it and conducted its short-term energy trades under this umbrella agreement. The model contract that the department attached to the February 2, 2001, request for bids was based on the power pool model contract. The second model form the department used, and the form that was generally used for contract negotiations, was based on the EEI model contract.

Both the EEI and power pool contracts were designed to assure reliability of price; they treat the sale of electricity as a purely financial transaction on the wholesale electricity trading floors of deregulated markets where electricity is traded as a commodity. While these two proposed contracts are different in form, they both focus upon addressing sellers' needs for credit assurance. They fail, however, to take into account the department's need, as effectively the largest utility in California and as the purchaser of the net short, to ensure delivery of power at the time and price promised. The department chose to use these model agreements without modifying them to meet particular needs that it, for example, identified in later contracts. As we discussed earlier, utility professionals have reportedly recognized since the EEI agreement was being developed, that those entities that require reliable power, such as those that serve retail loads, will need to modify the terms of the model form to address the absolute need for physical delivery of power.

Utility professionals have recognized that those who require the physical delivery of power will need to modify the terms of the model form agreement.

By using the EEI and power pool models as the basis of negotiation, the department proposed contracts meant to enable the liquid trading of energy in competitive markets where supply is sufficient to meet demand. Without modification, they are not structured for the single, bilateral transactions that meet the needs of the department in its role as the sole purchaser of California's net-short position. Further, the two agreements are not adequate instruments for a buyer in an unstable market with insufficient supply. Using the power pool and EEI model contracts was not, in itself, a bad choice; they are standard agreements familiar to generators and therefore permitted rapid contract negotiations. The problem was that the department failed to modify the forms to meet the particular needs of the State, given the role of the department and the market conditions.

As we explain in the remainder of this section, the lack of these provisions (or provisions with similar impacts) led to two critical problems. First, by failing to seek these types of provisions, the department was not able to determine whether it could have obtained these provisions from sellers and still achieve its policy goals. Put simply, if you do not ask for something, you will not know what, if anything, it would cost to get it. Second, and of equal importance, the lack of these types of provisions in the model contract prohibited the negotiators and legal consultants from having a ready checklist of provisions that should be included in specific agreements as the agreements in principle were crafted into contracts.

The Form Contracts Lack Five Provisions That Would Have Helped Ensure Reliable Delivery of Power

The availability of power and efficient markets were far from certain in the winter of 2001. To contractually address this problem and enhance the reliability of supply, at least five contractual modifications or enhancements should have been considered for inclusion in the form contracts. These provisions would have done the following: (1) defined failure to deliver as an event of default, (2) assessed penalties for unexcused failures to deliver, (3) provided availability guarantees, (4) required operation and maintenance within prudent industry standards, and (5) given the department the right to inspect and monitor the generator.

The Form Contracts Should Have Defined Failure to Deliver as an Event of Default

The form contracts should have treated failure to deliver as an event of default giving rise to an event of termination. Instead, the form contracts' exclusive remedy for failure to deliver, even repeatedly or deliberately, is cover damages.

Under the ISO's Summer Reliability Agreements, a seller's promise to deliver power is a material obligation, the breach of which constitutes an event of default.

Generally, buyers that have an obligation to provide power ensure that their contracts contain some type of default provision for the seller's failure to deliver. For example, such a termination provision is contained in the ISO's Summer Reliability Agreements (agreements) executed by generators late in 2000. Under the agreements, a seller's promise to deliver power is a material obligation, the breach of which constitutes an event of default. Given the fact that the department needed to assure delivery of power to fulfill its obligation to serve the State's net-short position, it would have been both logical and simple to adapt the agreements' termination provision and include it in the standard contracts. Even when the department was purchasing power only for the State Water Project and the utilities were still obligated to deliver power to the department, some of the department's power-purchase agreements state that failure to deliver is an event of default.

A wide range of circumstances can be defined as an event of default that permits termination of a contract. The harshest of these calls for termination with accelerated damages after a single failure. A more lenient provision would give the buyer, after a seller's repeated and deliberate failures to deliver, a termination right with no right to damages. Clearly the generators would

The real issue is why no termination right of any kind for even the most egregious failure to deliver was included in the form contracts.

not have agreed to the harshest remedy, but we believe it would have been difficult for a generator to reject a more lenient clause, provided that its repeated and deliberate failure to deliver is an event of default, giving the department a right to terminate the contract without damages. Failure to accept such a provision would call into question the good faith of any seller. Indeed, such clauses were included in a few of the later contracts. The real issue here is why no termination right of any kind for even the most egregious failure to deliver was included in the form contracts.

The Form Contracts Assess No Penalties for Unexcused Failures to Deliver

Under the contracts as drafted, sellers are not penalized for repeated or intentional failures to deliver but must simply make the department whole by providing cover damages. The inclusion of such penalties would provide incentives to ensure that sellers uphold their end of the bargain and deliver power as required by the contract.

The Form Contracts Contain No Availability Guarantees

The form contracts also fail to mandate availability criteria and, as a result, do not provide sellers with incentives or penalties to motivate the seller to deliver energy when it is needed. In essence, availability is the ability to produce and deliver energy. Generators cannot supply energy if their facilities are shut down for maintenance, inoperable because of unplanned outages, or not ready to produce energy for any other reason. Unless the seller is providing firm energy, the availability of a unit or defined set of units is critical to the reliable delivery of energy when needed. Thus, it is common in the industry to provide a mechanism to compensate the seller based upon availability or to provide penalties and incentives to motivate availability.

The Form Contracts Contain No Requirement for Operation and Maintenance Within Prudent Industry Practice and No Rights to Inspect and Monitor the Generator

The final two provisions that should have been seriously considered for inclusion in the form contracts also relate to generator availability and performance. The inclusion of a provision that requires operation and maintenance in accordance with prudent industry practice would have established a standard of care on the part of the seller. In addition, a provision giving the

The right of inspection would have permitted monitoring of the generator over the life of the contract.

department the right of inspection would have permitted monitoring of the generator over the life of the contract. These two provisions are interrelated and, in effect, set a standard and policing mechanism for generator operation. Given the goal of reliability and the allegations of unnecessary, unscheduled outages combined with certain generators' purported unwillingness to allow access to their facilities during the peak of the crisis, inclusion of these provisions would have provided the department added assurance of reliable operation.

The Form Contracts Lack Three Provisions That Would Have Helped Ensure the Construction and Maintenance of Required Generation

In addition to the lack of provisions assuring reliability of delivery, the form contracts lack provisions ensuring that new generation will be built and maintained, if such new generation is promised in a contract. This omission deprived the department of a means of putting sellers on notice as to the department's minimum standards for new units and also deprived the negotiators of a checklist of provisions to look for when reviewing sellers' draft agreements. Including these provisions would have enhanced reliability by increasing the likelihood that a unit would be constructed on a timely basis and, if a seller's construction progress lagged, would provide the department with notice of problems and the ability to either address the problems or enforce the contract in other ways.

The first critical construction-related provision that was not considered or included in the form contracts is one that mandates construction (unless the seller can demonstrate why, after the seller's best efforts, construction is impossible to complete) and penalizes the seller for a failure to complete the unit. Typically, such provisions are coupled with security to ensure that the buyer is paid upon a seller default.

Second, the form contracts should have included construction milestones. Again, such milestones are typically coupled with incentive and penalty provisions to provide sellers with appropriate price signals for timely construction. It was not until March 2001 that the department—through its energy consultant—notified the market that it sought milestones and other availability guarantees for new generation.

Finally, the department should have seriously considered including provisions that permit a court to order specific performance of the contract or to allow the department (or another State agency) to step into the shoes of a nonperforming seller and take over construction of any facility that is not complete. Specific performance is a remedy under which courts can order the nonperforming party to do what it has agreed to do, rather than providing monetary damages to the other party. It is used when money alone cannot cure the harm. Courts are often reluctant to award this remedy, however, especially in cases of breach of contract, in which they often presume that cover damages are adequate to cure any harm. Accordingly, parties that feel they will need specific performance if there is a future breach often seek agreement at the outset that money will not adequately compensate for a breach and that specific performance should be allowed.

The Department's Legal Team Lacked Resources When Drafting the Form Contract

In the rush to put out a form contract, the ISO model contracts, which are more closely designed to fit the department's role of provider of the net short, were not reviewed.

The problems with the form contracts—and with the deals that conformed closely to those forms—stem at least in part from a failure to commit adequate time and resources to the legal review of the form contracts. According to the department's legal consultants, to enable the negotiating team to move quickly the negotiating team's focus was on whether the form contract would adequately achieve the business goals of the department and not on including all of the provisions that would typically exist in a contract that was negotiated over a long time period.

Although the department originally proposed reviewing ISO contracts, which we view as more closely designed to fit the department's role of provider of the net short, in the rush to put out a form contract, the ISO terms and conditions were not reviewed, let alone included in the form. On the sellers' side, the department was faced with multiple parties, each presumably represented by sizable teams of in-house and outside counsel. While the department had the clear statutory authority to hire the necessary expertise (at the appropriate salaries) to perform its new function, according to the department, the decision to move quickly prevented it from taking full advantage of this authority.

The suppliers may have possessed superior leverage; but it appears the department never asked for certain provisions to protect reliability for the bulk of the power.

In short, the extreme time pressures imposed upon the task, at least in part, resulted in sellers being presented with form agreements that may not meet the reliability goals of AB 1X. It may well be that the suppliers possessed superior leverage and would have bargained these provisions out of the final agreements. It may also be true that the price paid under the contracts is sufficient in and of itself to provide the incentives necessary to both build and operate the generating units supplying the power. However, because it appears that the department never asked suppliers for these types of provisions for the bulk of the power contracted for we cannot ascertain whether, and at what cost, sellers would have agreed to them.

THE EVIDENCE SUGGESTS THAT THE DEPARTMENT MAY HAVE OBTAINED BETTER TERMS THAN THOSE REFLECTED IN THE EARLY CONTRACTS

There is reason to think that the department may have obtained better reliability assurances in the early contracts if it had asked for them. Such provisions were included in some of the later, smaller contracts, and this inclusion does not appear to be due solely to the fact that these contracts were entered late nor to the fact that they are small.

Our "Report Card" Summary Confirms That the Terms of Later Contracts Are More Favorable Than the Terms of Earlier Contracts

As part of the audit process, we "graded" the bulk of the contracts using a report card format with different categories based on the contract's (1) reliability of delivery, (2) reliability of availability, (3) reliability in the development of new generation, (4) potential for cost increases, (5) proper balancing of tolling agreement risks, (6) flexibility for the department to renegotiate onerous terms, and (7) assignment flexibility. Using a –1 to +1 scale, we assigned grades to the contracts for each of these categories as follows: –1 indicates contracts that are unfavorable to the State, 0 indicates contracts that are neutral to the State's interests, and +1 indicates contracts that are favorable to the State. Table 8 summarizes the results of the grading process. Appendix C shows the grades in detail.

TABLE 8

Summary of Report Cards for Contracts Executed by the Department

Contracts Executed by March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
11	**Calpine**	7/1/01	10.5	Base	70,115	-3	-3	-3	-1	N/A	-2	0	-1
12	**Calpine**	8/1/01	20.0	Peak	7,958	-3	-3	-3	-1	N/A	-1	0	-1
13	**Calpine**	10/1/01	10.33	Base	64,596	-3	N/A	N/A	-1	N/A	-1	0	-1
6	**Dynegy**	3/6/01	0.83	Peak	4,094	-1	-2	N/A	-2	-1	-2	0	2
7	**Dynegy**	3/1/01	0.09	Off-peak	482	-1	-2	N/A	-2	-1	-2	0	2
14	**Dynegy**	1/1/02	3.0	Base	5,261	-1	N/A	N/A	-2	-1	-2	0	2
15	**Dynegy**	1/1/02	3.0	Peak	8,986	-1	N/A	N/A	-2	-1	-2	0	2
16	**Dynegy**	1/1/02	3.0	Peak	14,851	-1	-2	N/A	-2	-1	-2	0	2
17	**Dynegy**	1/1/02	3.0	Off-peak	1,747	-1	-2	N/A	-2	-1	-2	0	2
8	Williams	4/1/01	10.0	Peak	10,006	-2	1	N/A	-2	N/A	-3	0	0
9	Williams	6/1/01	4.5	Peak	4,578	-2	1	N/A	-2	N/A	-3	0	0
10	Williams	6/1/01	9.5	Base	21,983	-2	1	N/A	-2	N/A	-3	0	0
18	Williams	1/1/03	8.0	Peak	19,968	-2	1	N/A	-2	N/A	-3	0	0
		Total gigawatt-hours:			**234,625**								
		Average scores:				**-1.77**	**-1.00**	**-3.00**	**-1.77**	**-1.00**	**-2.15**	**0.00**	**0.69**

continued on next page

Agreement in Principle by March 2, 2001; Contract Executed After March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
19	High Desert	7/1/03	8.25	Base	51,896	-2	-3	2	1	N/A	-2	2	0
20	Constellation	4/1/01	2.25	Peak	2,246	-1	N/A	N/A	1	N/A	-2	2	2
27	**Allegheny**	1/1/03	1.0	Peak	749	-1	N/A	N/A	1	N/A	-2	0	2
21	**Allegheny**	3/23/01	0.58	Peak	1,270	-1	-1	N/A	1	N/A	-2	0	2
22	**Allegheny**	10/1/01	10.25	Base	61,880	-1	-1	N/A	1	N/A	-2	0	2
28	**Sempra**	6/1/01	10.3	Peak	22,339	-2	-2	-3	0	1	-1	0	2
29	**Sempra**	4/1/02	9.5	Base	70,986	-2	-2	-3	0	1	-1	0	2
43	Cal Peak (ii)	10/15/01	10.0	Super Summer Peak	2,154	2	3	2	0	2	2	1	0
44	Cal Peak (ii)	10/15/01	10.0	Super Summer Peak	2,873	2	3	2	0	2	2	1	0
45	Cal Peak (ii)	11/1/01	10.0	Peak	0	2	3	2	0	2	2	1	0
	Cal Peak (ii)	11/1/01	10.0	Peak	0	2	3	2	0	2	2	1	0
40	Sunrise	8/1/01	1.42	Super Summer Peak	447	3	2	1	0	1	0	2	0
41	Sunrise	3/1/03	8.58	Base	38,441	3	2	1	0	1	0	2	0
		Total gigawatt-hours:			**255,281**								
		Average scores:				**0.31**	**0.64**	**0.67**	**0.38**	**1.50**	**-0.31**	**0.92**	**0.92**

Both Agreement in Principle and Actual Agreement Executed After March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
31	GWF	9/1/01	11.33	Summer Peak	23,713	3	3	1	-2	2	2	0	0
32	Mirant	6/1/01	1.5	Peak	3,952	-3	N/A	N/A	1	N/A	-1	0	0
33	**Coral**	5/24/01	11.25	Peak	13,520	1	4	3	1	1	2	0	0
34	**Coral**	7/1/03	11.25	Peak	5,049	1	4	3	1	1	2	0	0
35	**Coral**	7/1/02	10.0	Base	5,729	1	4	3	1	1	2	0	0
36	**Coral**	7/1/04	10.0	Peak	4,378	1	4	3	1	1	2	0	0
39	Pacificorp	7/1/01	10.0	Base	21,900	3	3	N/A	0	1	1	1	2
48	**Calpine SJ**	5/1/02	3.0	Peak	3,024	1	2	0	1	1	2	0	-1
		Total gigawatt-hours:			**81,265**								
		Average scores:				**1.00**	**3.43**	**2.17**	**0.50**	**1.14**	**1.50**	**0.13**	**0.13**

Grade summary

Average scores per period:	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	Assignment
Contract by March 2	**-1.77**	**-1.00**	**-3.00**	**-1.77**	**-1.00**	**-2.15**	**0.00**	**0.69**
Agreement in principle by March 2	**0.31**	**0.64**	**0.67**	**0.38**	**1.50**	**-0.31**	**0.92**	**0.92**
Contract or agreement in principle after March 2	**1.00**	**3.43**	**2.17**	**0.50**	**1.14**	**1.50**	**0.13**	**0.13**

Notes:

The grades shown here correspond to the overall grade for each category shown in Appendix C. Refer to Table 11 in Appendix C for the more detailed ratings of each contract.

N/A Attribute is not applicable.

(i) The product codes are explained in Appendix A.

(ii) Because the department separates the power from the Cal Peak contracts between parts of the year, it treats Cal Peak as four contracts. We show all four contracts here since our consultant evaluated the legal terms of each contract individually. Elsewhere in the report, we treat the transactions as two contracts.

Supplier names in bold indicate that they were reviewed in detail by our consultant.

Our report card analysis was far less rigorous than our detailed analysis of the contracts within the audit sample, and the results make no distinction between contract provisions other than good, neutral, or bad. (For example, the Calpine provision requiring the department to pay for any increase in Calpine's cost of service over 50 cents per megawatt-hour, while qualitatively worse, receives the same –1 for the price risk category as a provision requiring the department to pay for any increase in taxes directed at new generation.) Overall, however, grading the contracts reaffirmed our conclusions from the more in-depth analysis of the audit sample contracts: The large contracts executed prior to March 2, 2001, may not achieve the AB 1X goals of ensuring reliable power, and the contracts that do contain better reliability guarantees were executed later in the process.

The difference between the early large contracts and some of the much smaller, much later contracts is particularly striking. For example, the Sunrise contract makes it an event of default for the seller willfully to fail to deliver power and to deliver power ordered by the department to another buyer. In other words, if Sunrise willfully withholds power scheduled under its contract with the department in preference to another buyer, the department not only can terminate the contract, it can collect damages equal to the termination payment. This is similar to the provision in the ISO's Summer Reliability Agreements, discussed earlier, that makes failure to deliver an event of default. Other contracts, such as the GWF contract and the Wellhead-Gates contract, do not give the department the full protection of an event of default, but do allow the department to terminate the contract (without damages) if a seller's delivery is insufficiently reliable.

The difference between the early large contracts and some of the much smaller, much later contracts is particularly striking.

What is striking about these more favorable later contracts is that some are basically insignificant in terms of overall cost, size, and duration. Despite their smaller size and lower costs, it appears that at least as much attention to detail and effort went into the drafting of these contracts as went into the drafting of the early deals that dwarf them. For example, the Wellhead-Gates contract, which is for a mere 41.3 megawatts of peaking capacity at a total cost of about $160 million, contains more than 20 pages of transaction-specific terms—terms generally far more favorable than those of the Calpine Peaker contract, a deal involving 495 megawatts of peaking capacity for roughly 20 years at a total cost of about $2.9 billion.

A natural question to ask is whether the favorable terms in the smaller, later contracts could have been achieved in the earlier, larger deals. Again, while we cannot answer this question with certainty, we suspect that the less favorable terms contained in the earlier, larger contracts did not result solely from the fact that the department's energy "bucket" was relatively empty, nor solely from the fact that those deals are large. Our report card analysis suggests that the decision to negotiate the early contracts essentially simultaneously—without any significant time between deals for the department to learn from the executed contracts or to allow the market to react to the most current deals—likely resulted in the department receiving less favorable terms than it otherwise might have gotten.

Early in the Process Some Unsuccessful Proposals Contained More Favorable Reliability Terms

When we reviewed the bids in response to the department's two requests for bids issued January 23 and February 2, 2001, we found that some of the initial offers that did not ultimately result in a long-term contract contained a number of the reliability provisions we believe should have been in the form contracts as a starting place for negotiations. Although there may be multiple reasons why the proposals were not successful such as that the seller was not convinced of the department's creditworthiness, these offers demonstrate that at least some of the sellers assumed that the department was looking for reliability guarantees in the transactions and were willing to provide them depending on the overall terms of the deal.

In response to the second request for bids, one proposal is notable in that it contains several of the components that are key to assuring reliable delivery of power and price stability.

For example, in response to the second request for bids, by letter dated February 6, 2001, a generator submitted a proposal contemplating construction of new units that would provide approximately 750 megawatts per year for a 10-year period beginning September 1, 2003, and ending September 1, 2013. That proposal is notable in that it contains several of the components that are key to assuring reliable delivery of power and price stability:

- Minimum availability requirements (at least 95 percent for the summer peak period).
- Liquidated damages payable by the seller if the minimum availability guarantees were not met.

- Deadlines for the units to achieve commercial operation as well as milestone dates.

- Liquidated damages payable by the seller if the seller fails to achieve the commercial operation date.

- Air emissions credits that are the responsibility of the seller, not the department.

Although the proposal was for power to be supplied in 2003, it did not result in a consummated, long-term deal, primarily because the seller had creditworthiness concerns about the department. Nonetheless, the company's response to the department's request for bids indicates that, as early as February 6, 2001, there were sellers that assumed that these more favorable reliability terms were on the checklist of provisions that a seller would anticipate that a provider of the net short, like the department, would want to negotiate on when contracting for long-term power.

That generator was not the only seller to respond to the first request for bids with certain favorable reliability terms. For example, a second generator, bid for 5 years' delivery of 80 megawatts of firm summer super-peak power to commence June 2001, from generation not yet completed. The second generator was willing to commit to a firm commercial operation date on that deal. A third generator submitted six alternative proposals for varying quantities (100 megawatts up to 3,500 megawatts) and durations (5, 10, and 15 years), and with varying terms regarding fuel price risk (tolling, indexed, and firm energy). Many of these proposals—which in the third generator's view did not conform to the request for bids—contained a guaranteed availability factor (92 percent) and agreement to limit planned maintenance outages in accordance with "prudent" or "generally accepted" "electrical practice" and to provide the department annually with a schedule of planned maintenance for the upcoming year.

The contract terms did not improve significantly until it was too late to make a meaningful impact on the department's overall portfolio of contracts.

The Terms Regarding Reliability of Delivery Did Not Become More Favorable in Step With the Department's Progress in Filling Up the Net Short

As the department got more and more power under contract, its bargaining power should have increased steadily, and the contract terms should have become more favorable. Instead, although the vast majority of the megawatts were either under contract or the subject of an agreement in principle very early in the process

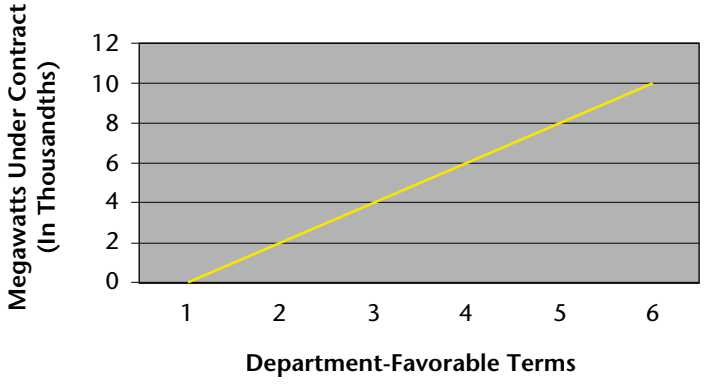
(that is, during the period from February 6 through March 2), the contract terms did not improve significantly until it was too late to make a meaningful impact on the department's overall portfolio of contracts.

In late January, the State was making energy purchases in the spot market, which was costly, inefficient, and unstable. The State's long-term "energy bucket," at least on the margin, was empty and needed to be filled with energy contracts to ensure that the State would have reliable power and to stabilize the runaway energy market. Given the circumstances, suppliers clearly had superior bargaining power.

In this context, one would expect that the terms for the first major contract would be among the worst (the least favorable to the department) because demand was very high and the energy bucket was empty. Over time, however, one would also expect that the contractual terms would become more favorable to the department because its bargaining power would increase as the energy bucket filled and the urgency of the energy shortfalls would be reduced. Although not precise, one would expect to see a graphical relationship like that in Figure 8 between the favorability of contract terms and the number of megawatts under contract. In short, as the bucket fills, the parties' respective bargaining power should become more balanced and contract terms should become more favorable to the department.

FIGURE 8

Bargaining Power Expectations



Source: Pierce Atwood analysis.

Although it appears that the earliest contracts were in fact the least favorable to the department, our other expectation appears not to have been fulfilled. Rather than seeing the terms get gradually better with each large, long-term contract, we see terms that are fairly uniformly less favorable early on and that markedly improve rather suddenly later.

The early Calpine agreements stand out overall as having the most seller-friendly provisions of any major contract we reviewed.

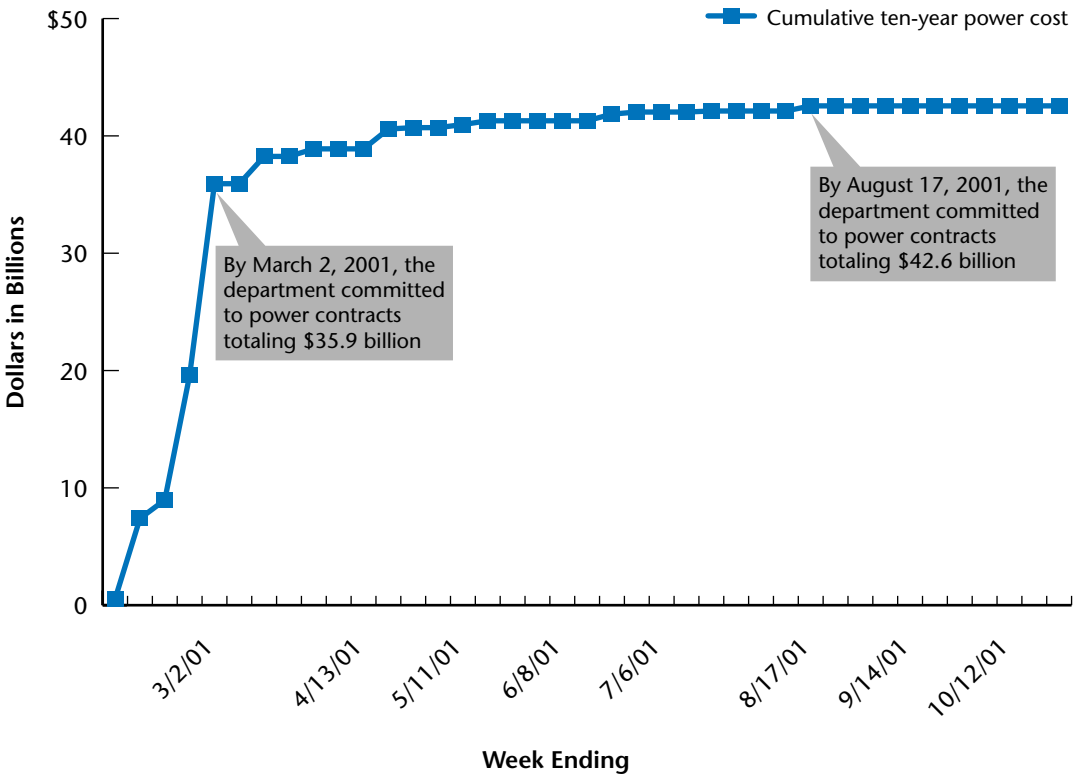
The early Calpine agreements stand out overall as having the most seller-friendly (and least favorable to the department) provisions of any major contract we reviewed. Unfortunately, rather than reflecting more favorable terms while the energy bucket was rapidly filling, the contracts fairly consistently contain terms that are unfavorable to the State, such as high pass-throughs of new taxes and other government-imposed charges, pass-throughs of emissions and environmental costs, and lack of any significant reliability guarantees. The contracts the department entered into after March 2 not only contain more favorable terms than the earlier contracts, but also got increasingly better over time as the department's bargaining power increased. As Figure 9 shows, however, the bulk of the power was already under contract.

We do not know the extent to which the department could have negotiated more favorable terms if, for example, following execution of the Calpine agreement, the negotiators had briefly delayed negotiation of additional agreements while (1) reflecting on the Calpine deal, (2) identifying terms that should be avoided in future contract negotiations, (3) developing a strategy for obtaining more favorable terms, and (4) letting the market "cool down" following this large purchase. We do know, however, that an agreement in principle on the Coral deal was reached 2 weeks after the department took full control over contract negotiations, but in contrast to the rapid pace that marked the earlier period, the terms of the Coral contract were not finalized for more than 2 months after the agreement in principle was executed. The Coral contract provides for significant power (about 28,700 gigawatt-hours), and its terms are significantly more favorable to the department. Indeed, the contract contains many of the reliability, availability, and new generation guarantees that are lacking in virtually all of the contracts agreed to in the intense contracting period. Similarly, the contract with the most favorable termination provisions of any contracts we reviewed—the Sunrise agreement—was agreed to in principle in early March but was not finally executed until months later. Like the

The failure to achieve more buyer-friendly terms appears to be due, at least in part, to the speed with which they were negotiated and the failure to request more favorable terms in the request for bids and the negotiation process.

FIGURE 9

The Majority of the Department's Power Was Negotiated by March 2, 2001



Source: Analysis by LaCapra Associates using data from the Department of Water Resources.

Coral contract, it is a substantial power purchase, involving almost 39,000 gigawatt-hours over 10 years at a total cost of more than $2.1 billion.

In short, forging full speed ahead meant that the terms for the vast majority of the megawatts contracted for never got significantly better in the four weeks during which they were negotiated. This does not appear to be a function merely of the large size of the contracts, nor of the size of the net short remaining to be secured under long-term contracts. It is apparent from later deals that sellers were willing to commit significant amounts of power to the department on more buyer-friendly terms than those contained in the early, large contracts like Calpine, Williams, and Dynegy. The failure to achieve more buyer-friendly terms in these early, large contracts appears to be due, at least in part, to the decision to move rapidly, which resulted in less favorable terms being requested in the request for bids than we saw included in later contracts. ■

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CHAPTER 3

The Department's Resources Were Insufficient for Handling Short-Term Power Transactions, but It Managed to Meet the State's Power Needs

CHAPTER SUMMARY

The Department of Water Resources (department) was ill prepared for the magnitude of the task involved in its new role of purchasing enough power to ensure that the daily power needs of the State were met. The magnitude of the task required that the department, disadvantaged by a general lack of creditworthy buyers and a dysfunctional market, purchase large amounts of power each day from highly qualified and market-savvy sellers. However, the department lacked the infrastructure and enough experienced and skilled staff needed to perform at this level. As a result, while the department struggled to purchase needed power, it simultaneously struggled to establish the organization that it would need to meet the challenge.

Despite its limitations, however, the department was able to fulfill this role. From January 2001 through August 2001, the department spent more than $8 billion for power in short-term transactions, such as day-ahead, hour-ahead, and real-time purchases. Beginning in June 2001, the department's spending for short-term energy transactions declined along with spot market prices due to reduced generator outages and natural gas prices as well as reduced demand for power. The department's future spending for short-term transactions should continue at lower levels than 2001 because of lower forecasted spot market prices and a reduced dependency on short-term transactions. Although the department has filled the energy gap created by a financially distressed market, the future availability of adequate power in the real-time markets of the California Independent System Operator (ISO) may be in jeopardy due to unsettled purchases and delayed payments to electricity sellers.

The department has not yet implemented the infrastructure and hired the staff required to meet its continuing challenges. For example, the department is still developing systems to coordinate with the investor-owned utilities to forecast demand, schedule available power at the lowest cost, and manage the risks in its portfolio of contracts.

To furnish a context for our description of the department's short-term transactions, the following discussion addresses the workings of the California electricity market to a great level of detail. Appendix D summarizes the structure of the California electricity market and provides background for the discussion and definitions of the terms used.

THE DEPARTMENT WAS ASSIGNED A LARGE TASK DURING EXTREMELY DIFFICULT MARKET CONDITIONS

The California Energy Resources Scheduling Division (division), a division created by the department for operating its Purchase and Sale of Electric Power Program (power-purchasing program), was assigned the job of purchasing the investor-owned utilities' net-short position at a very difficult time. The *net short* is the difference between consumers' demand for electricity and the amount of electricity provided by the utilities' generation and by contracts with wholesalers of electric power. Real-time purchases were supplying the large volumes of electricity needed to meet the net short, sellers' concerns over buyers' creditworthiness were elevating spot market prices, and physical shortages of electricity had occurred regularly during the previous months. Several of the important market fundamentals—as well as spot market prices—were well outside historical ranges. The division, as the only creditworthy power buyer for customers of the investor-owned utilities, entered a market in which the historical relationships and rules of market analysis did not apply.

The Department's Most Immediate Challenge Was to Begin Making Daily Purchases to Supply More Than One-Fourth of the Electricity Needed by California's Investor-Owned Utilities

During late 2000 and early 2001, demand for electricity in California began to approach the available supply for the first time in recent memory. During three days in January 2001 the ISO implemented statewide rolling blackouts to maintain the

balance between electricity consumption and available supplies, thereby preventing potential outages to the regional electricity system as a whole.

At the same time, the California electricity market had come to rely heavily on hourly and real-time energy purchases, and it had insufficient generation scheduled to meet the ISO system load in almost all hours. According to the ISO, an average of nearly 4,200 megawatts of incremental generation each hour was required from real-time markets (the ISO real-time market and out-of-market purchases made by the ISO) during December 2000. This need was up from its previous average of 2,000 megawatts for hours of peak usage and 750 megawatts for off-peak hours. ISO real-time energy expenditures for the month of December 2000 alone amounted to more than $1.3 billion, a total that dwarfs the ISO's annual expenditures on real-time purchases of approximately $209 million in 1998 and $180 million in 1999.

The division began purchasing power to cover the investor-owned utilities' net-short position on January 17, 2001; for the balance of January, it purchased an hourly average of more than 4,350 megawatts, including much higher amounts during peak hours. By February, as the net-short position increased due to declining production from utility-retained generation, the division purchased an hourly average of more than 7,000 megawatts, again with much higher amounts during peak hours. For the month of February, division purchases amounted to more than one-fourth of the electricity consumed in the area within ISO control. The overwhelming majority of the purchases during the early weeks of the division's operation were made from the spot market on a daily, hourly, and real-time basis.

Market Fundamentals and Prices Were at Historically High Levels

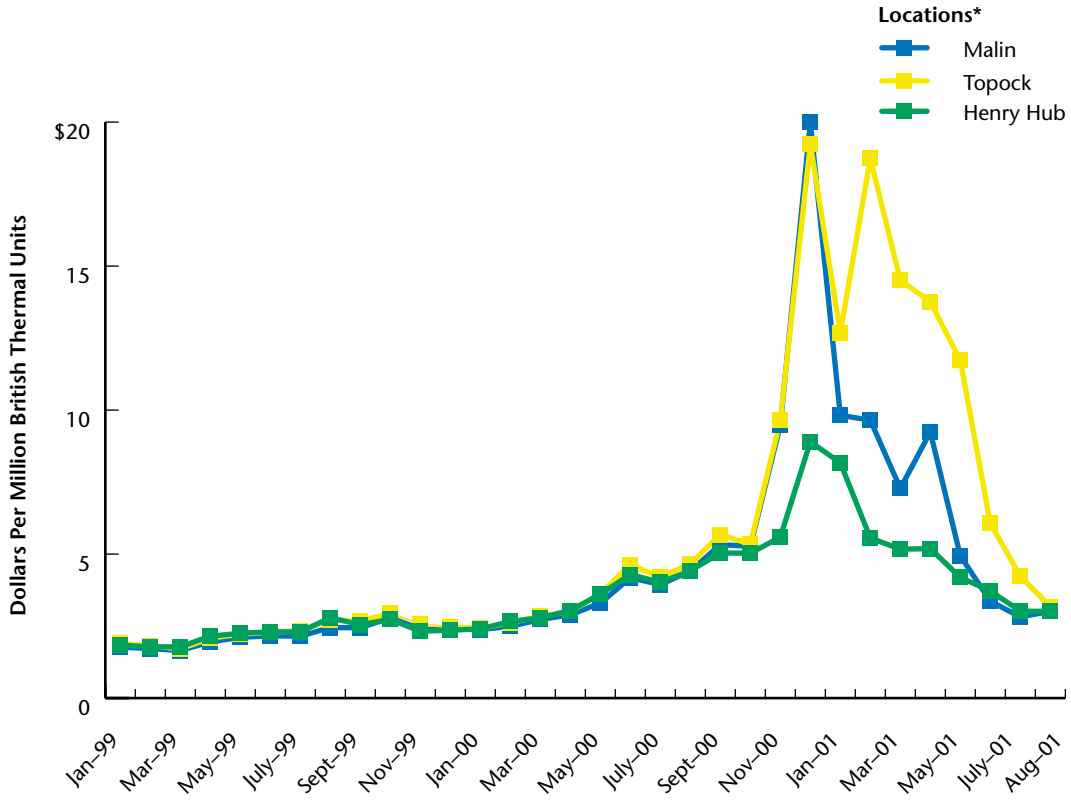
At the same time that the balance between supply and demand was closing, natural gas prices and emission allowance prices had soared above historical norms.

At the same time that the balance between supply and demand in California was closing, two key factors that affect the cost to produce electricity—natural gas prices and emission allowance prices—had soared far above historical norms. Figure 10 on the following page illustrates the monthly spot price of natural gas for two key locations in California along with the major pricing locations for gas in the United States from January 1999 to August 2001. Figure 11 on page 125 presents the price of allowances for the emission of a certain air pollutant, oxides of nitrogen (NOx), in the South Coast Air Quality Management

District (South Coast district) for certain days in 2000. During the previous six years of trading, these allowances had traded for less than $4 per pound, an amount less than one-tenth the $45 per pound observed in late 2000 by the ISO. These allowances represent a variable cost (or an opportunity cost) of production for generating units located in the South Coast district. To understand the effect of this price increase, consider that an allowance price of $40 per pound translates into an emission-related cost of $80 per megawatt-hour for a typical combustion turbine burning natural gas, as opposed to emission-related costs of $12 per megawatt-hour when the allowance price is $6 per pound.

FIGURE 10

Monthly Averages for Natural Gas Spot Prices
January 1999 Through August 2001

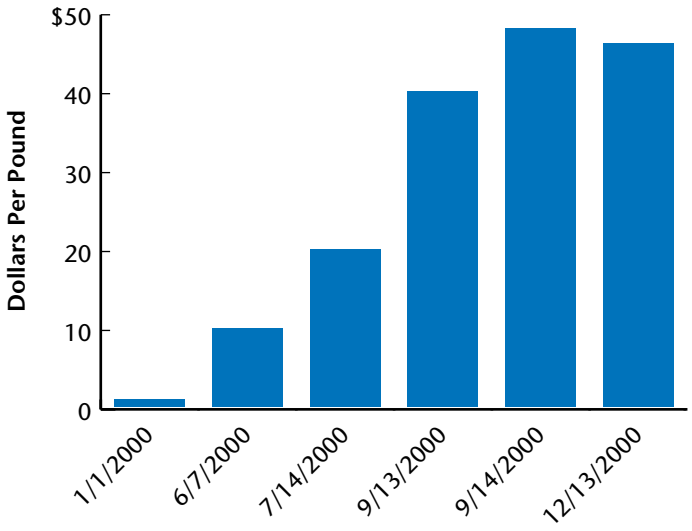


Source: *Gas Daily*

* These locations are delivery points for purchases of natural gas and are used to track and set prices.

FIGURE 11

2000 Prices for Emission Allowances for Oxides of Nitrogen in the South Coast District



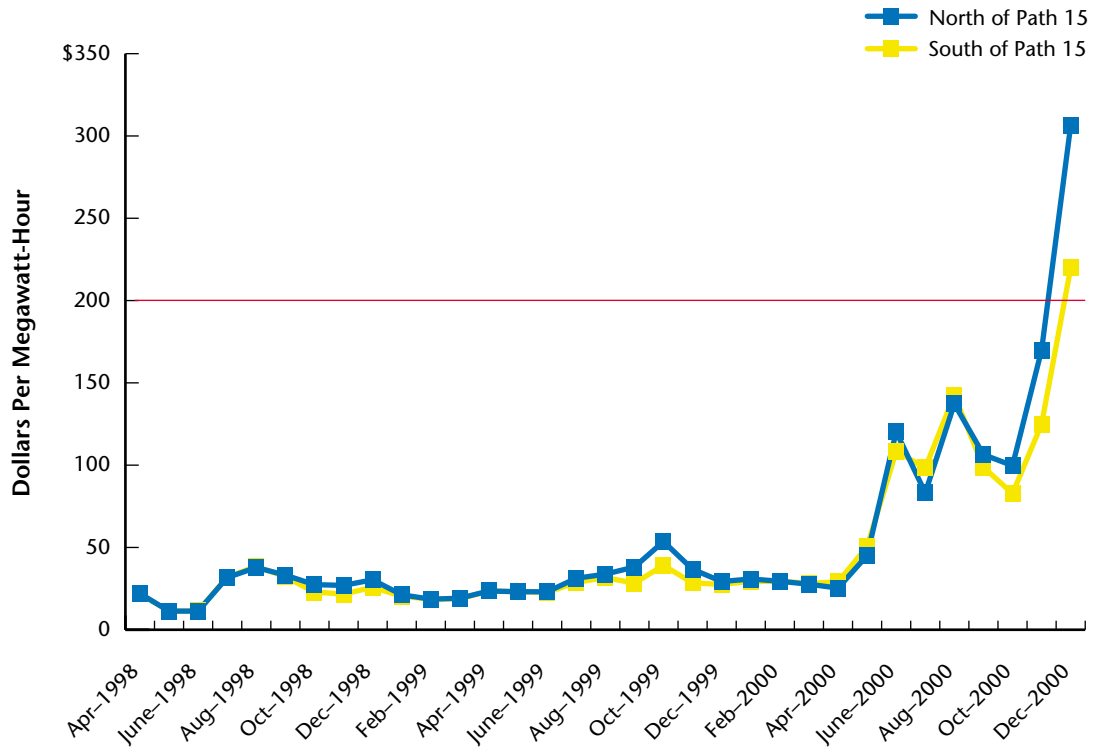
Source: December 2000 Market Analysis Report from the California Independent System Operator.

These cost increases at gas-fired plants were important because prices in the electricity market tend to be defined by the bids of the suppliers with the highest costs even though hydro, nuclear, and coal plants with lower variable costs provide much of the energy in the market. In California, soaring generation costs at gas-fired units were essentially increasing the price for all energy traded in the spot market.

At the time the division entered the market, the tightening supply and increasing costs had combined to produce large increases in electricity prices in California's spot market. As shown in Figure 12 on the following page, day-ahead energy market prices in December averaged well over $200 per megawatt-hour for areas south of Path 15, which is the main transmission line between Northern California and Southern California, and $300 per megawatt-hour for areas north of Path 15. These prices were up from historical monthly averages of $20 to $50 per megawatt-hour. Real-time energy purchases by the ISO averaged $423 per megawatt-hour in December and $290 per megawatt-hour in January 2001. Similar high electricity prices prevailed in neighboring western states.

FIGURE 12

Monthly Average for Day-Ahead Market Prices
April 1998 Through December 2000



Source: Database from the *Power Markets Week Price Archive*.

The Department Struggled to Fulfill Its Role as a Creditworthy Purchaser for the Net-Short Position

One of the primary reasons that the division was created was to establish a creditworthy buyer for power to serve the net-short position of the investor-owned utilities. Without pledging its full faith and credit, the State stepped into this breach with a legislative package containing provisions apparently intended to give the division a solid credit foundation. However, the enactment of Assembly Bill 1X (AB 1X) alone did not solve the credit challenge. In addition, the inability of the department to issue bonds authorized by AB 1X caused concern regarding the program's creditworthiness. The department needed to take steps to establish itself as a creditworthy buyer in the market. As the department responded to its statutory mandate, its efforts to secure supplies in short-term power markets were immediately hampered by questions regarding its ability to pay for power

purchases. According to the division's deputy comptroller, sellers had not been paid for two months before the department's entrance into the market. Because the program's liabilities were backed only by the Department of Water Resources Electric Power Fund (electric power fund), the department had to convince sellers that the financial underpinnings of its power-purchasing program would ensure payments for purchased power. In addition, it had to develop payment terms that would be acceptable to sellers during the frenetic early days of the division's operations.

With the major market participants financially stressed from rising costs, the department struggled to convince reluctant sellers that it was creditworthy.

According to the deputy comptroller, some of the division's initial generation suppliers sought special payment terms to reduce their credit exposure and gain assurance that they would be paid. The department found it necessary to offer early payment terms to six or seven suppliers. In these cases, the suppliers would receive payments, discounted for interest lost by the department for the early payments, upon delivery or soon thereafter, rather than on the 20th of the following month, which was the customary date for such purchases.

Prior to the passage of AB 1X, the department purchased temporary financial backing from a commercial bank in the form of a letter of credit. However, given the department's volume of purchases during late January and early February, the limit of the letter of credit was quickly reached, and it was not renewed. The department chose not to continue the use of letters of credit in early February 2001 as it believed that the continuing appropriations under AB 1X were adequate to support purchases made under the power-purchasing program. In addition, by eliminating letters of credit the division sought to remove the possibility that suppliers would request letters of credit in any long-term contracts. Over time, the department's efforts seemed to offset many suppliers' initial hesitancy to incur substantial credit exposure to the division.

However, it is not clear that the division or the State took sufficient steps to communicate to already nervous suppliers that the division is an entity with which they could do business confidently. Aside from periodic letters that the department issued to market participants informing them of the financial position provided the program by the Legislature's actions, we find little evidence of a concerted effort to approach and educate generation suppliers aggressively about the division's mandate, the statutory and financial framework that had been established to support the division, and the division's creditworthiness.

We see two potential problems with this lack of a coordinated effort to communicate with suppliers. First, the piecemeal effort to educate generation suppliers regarding the division's role and creditworthiness represented a drain on the time and energy of division staff in its endeavor to secure a reliable supply of electricity at reasonable cost. Second, it is unknown but possibly had a dampening effect on the number and price of offers that the division received to meet the net-short position. The division's manager of energy scheduling and trading indicated that supplier credit concerns limited the range of available trading partners in the early months. As a result, the division sometimes had other entities purchase power on its behalf, a process known as *sleeving*, to conceal the fact that the department was actually buying the power. This condition increased the power purchase price. In addition, some market participants still will not sell to the division. It is possible that a more comprehensive campaign by the division or another state agency to convince suppliers of the division's creditworthiness might have yielded better results.

According to the department, in its view, conditions were changing so rapidly that the daily, if needed, contacts with suppliers were the most effective way to proceed and it believes its efforts proved successful.

THE DEPARTMENT'S POWER TRANSACTION AND OPERATIONS TEAM LACKED ADEQUATE STAFF

According to a department official, the department was the only state agency with utility qualifications. As the division's former deputy director said:

> "Our government couldn't get into the power business in a big way without asking an agency that already had the capability to do it. The reason for that is the Constitution, which requires a three-month lag time from the moment the governor signs a law into effect before an agency can be established. A three-month lag time would certainly not work during an emergency . . . so they were looking for a state agency that had an existing capability to meet the constitutional requirements. We were the only ones in government that operated a utility."

The department's capabilities were dwarfed by the magnitude of its mission under the power-purchasing program.

However, while the department may have been the best and only state agency for the task, its status as an operating utility was no assurance that it was fully qualified to conduct the magnitude of

power transactions associated with this role. Indeed, the department and its consultants understood from the outset that it was a relatively small utility in this context.

The department's prior experience with the State Water Project involved operations that had a much smaller scale than the activities required to purchase the net short for the investor-owned utilities. To purchase power for the State Water Project in fiscal 1999–2000, the department reported spending $125 million, a small fraction of the $8 billion that the division spent purchasing power in the first eight months of 2001.

The Department Was Prompt in Assessing Its New Business Requirements

With the assistance of its consultants, the department began a needs assessment for its power transactions operation in January 2001. The consultants quickly established that the organization needed to expand substantially in size and function in order to operate the power-purchasing program in an effective manner. Based on this needs assessment, the department established the division as a distinct unit to administer the power-purchasing program. The department proposed that it would provide the division with a budget of more than $22 million and a planned total staff of 88 people by the end of March. The department initially organized the division into three segments:

Energy and Reliability Trading—responsible for conducting day-ahead and real-time procurement and grid scheduling of power and transmission, settlement, ISO coordination, and information system support for all of these functions.

Energy Commodity—charged with procuring and managing forward contracts for power, planning and managing the contract portfolio risk, and contract administration.

Staffing at the Department and at Comparable Utilities

- **Southern California Edison,** a 19,000 megawatt* utility, has 30 staff working in its contracts sections alone.
- **California Independent System Operator (ISO),** which schedules 46,000 megawatts at peak, has 441 staff, 95 consultants, 190 full-time and part-time contractors, and 19 security guards.
- **Long Island Power Authority,** a 4,000 megawatt utility, has 70 staff just for contract administration, strategy, and billing. It contracts for all operations, including the trading desk, to a separately created entity that handles energy procurement, including real-time functions, on its behalf.
- **Sacramento Municipal Utility District,** a 3,000 megawatt municipal utility, has 32 energy traders (including some gas). This district has 8 to 9 staff for handling settlements.
- **Department of Water Resources,** on January 17, 2001, had about 14 staff who scheduled, traded, reconciled, and settled power purchases for the State Water Project.
- **The California Energy Resources Scheduling Divison**, which is part of the Department of Water Resources, was projected in February 2001 to be responsible for purchasing 11,000 megawatts, and planned 34 staff for trading, settlement, risk management, and procurement.

Source: Deloitte & Touche Presentation, March 12, 2001. The Department of Water Resources' Budget Change Proposal, February 28, 2001.

* Megawatts are the peak power requirement that the entity needs to obtain for one hour.

Market Analysis and Fiscal—directed to manage market and credit risk, analyze the market, and to oversee revenue administration, financing, and regulatory coordination.

The Department Has Had Serious Difficulties in Staffing the Division

Staffing of the division's operation has been and remains a distinct challenge and risk factor. The department has used many measures to staff for this responsibility, including using existing department staff, hiring additional staff, retaining experts under personal service contracts, and outsourcing to consulting firms. For the first several weeks, the department accomplished much of the staffing with its own personnel, retired department employees, and the creation of an emergency operations center. The department outsourced many of the activities to consulting firms and relied on those firms to provide staff for many functions.

Facing the difficulties of fully staffing a new organization, the department relied on existing department staff, retirees, and consultants, to purchase over $1 billion of power a month.

The department reports that retaining and recruiting employees for the division's function was highly problematic. This responsibility came at a time when the department had a high number of job openings and problems with recruiting and retaining employees. The department's recruiting of full-time staff was also hampered by the lack of qualified candidates for professional positions in the division's organization. The department believes that its ability to increase staffing also appears to have been hindered by the fact that, unlike private market participants, it must hire in the existing civil service structure. Without the ability to offer competitive salaries to power-trading professionals, the department remains well short of the full division staff of 88 people that the department had originally planned.

The chronic staffing problems at the department during a period when the trading operations were handling more than $1 billion per month in transactions are a matter of considerable concern. This problem persisted and continues to persist, in spite of the powers conferred by the State to ensure that the department has adequate staff. Specifically, AB 1X recognizes that "in order for the department to adequately and expeditiously undertake and administer the critical responsibilities established in this division, it must be able to obtain, in a timely manner, additional and sufficient personnel with the requisite expertise and experience in energy marketing, energy scheduling, and accounting."

The legislation states that the department may, as it determines necessary for the purposes of the power-purchasing program, do the following:

- Hire and appoint employees as required, at salary levels determined by the director to be competitive to attract and retain persons with the necessary expertise and skills.

- The State Personnel Board and the Department of Personnel Administration shall assist the department in expediting the hiring of personnel necessary and desirable for the timely and successful implementation of the department's duties and responsibilities under the program.

- Engage the services of private parties to render professional and technical assistance and advice and other services in carrying out the purposes of this division.

The department attempted to obtain approval of its staffing plan in April 2001 using a job classification for technical positions that it planned to use also for similar technical positions in the State Water Project. However, the state agency responsible for granting the approval for the positions, the Department of Personnel Administration, rejected the proposal because it judged the job classification too broad to meet a primary purpose of the civil service system, which is to ensure that positions involving comparable duties and responsibilities are similarly classified and compensated.

The division's continued inability to reach desired staffing levels and its reliance on consultants and contractors inhibits the development of the division organization and the important functions that were established in the spring of 2001. According to a division official, the tight staffing situation also appears to have taken a toll on division and department employees; many employees who worked during the crisis and have since returned to their normal job assignments have been unwilling to transfer permanently to the division. In this situation, the department's use of specialists and expert consulting firms is crucial to maintaining the division's operations.

Despite the hard work of the department's employees, it lacked enough properly skilled employees to carry out the program.

It is important to note the hard work and dedication of division and department employees during the time of emergency. Their contributions have been significant, particularly in light of the department's difficulties in recruiting personnel to fully staff the division.

An internal memo issued in February 2001 indicates that better risk management and administration of utility operations could have saved millions of dollars.

However, with so much money at stake through the magnitude of power purchases, hard work by employees has not been enough to handle the division's duties. The department required a sufficient number of adequately skilled employees to carry out the program. In its request for positions to staff the division, the department points out that energy trading and purchasing is a highly complex business with millions of dollars of energy purchased every day. It is important to recognize the level of risk and the high level of expertise necessary to manage that risk and operate the program effectively. In an internal memorandum issued in February 2001 regarding the department's progress in assembling its power-purchasing program, the division's former deputy director indicates that millions of dollars spent daily likely could have been saved through better risk management and administration of utility operations.

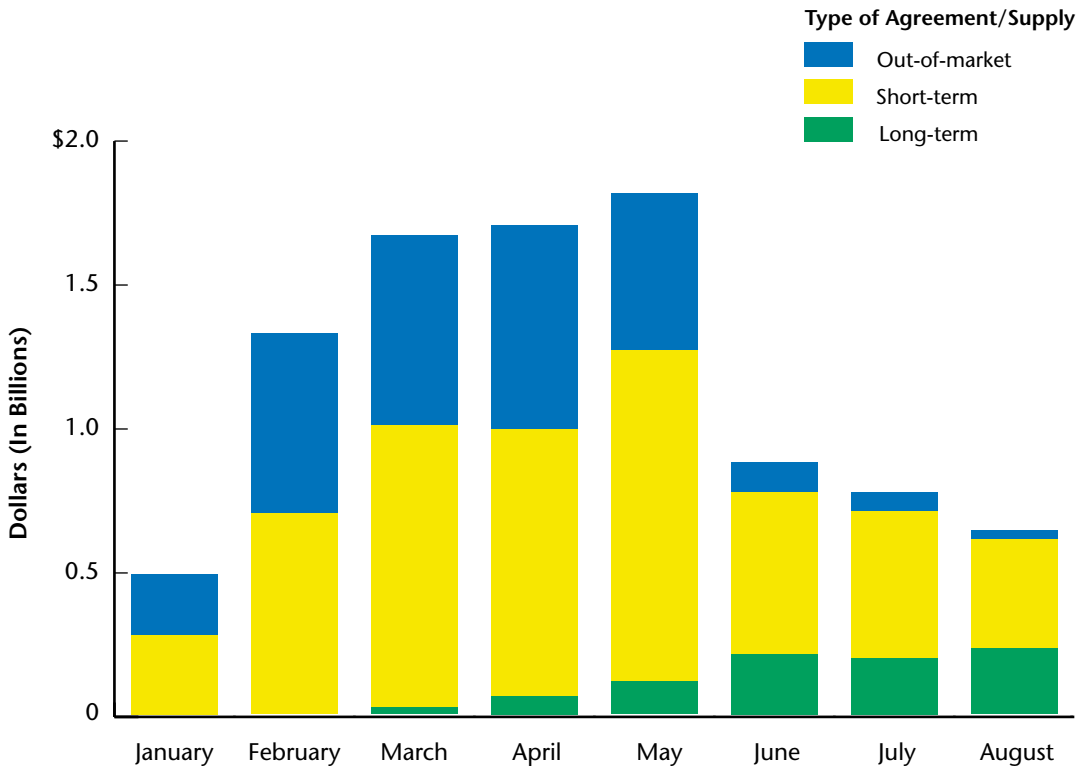
THE DEPARTMENT SPENT A LARGE AMOUNT ON SHORT-TERM ENERGY SUPPLIES, BUT EXPENDITURES HAVE DECLINED AND WILL PROBABLY REMAIN LOW IN THE FUTURE

Most of the division's market expenditures to date have been for short-term energy supplies. The division reported that from January 2001 through August 2001, it spent more than $8 billion on short-term energy supplies, buying a total of about 38,000 gigawatt-hours. As illustrated in Figure 13, the division spent well over $1 billion per month on short-term supplies from February 2001 through May 2001. This figure means that the division was spending between $30 million and $70 million per day on short-term energy supplies during the first several months of 2001.

During this period, the division obtained most of the investor-owned utilities' net-short position through spot market purchases and other short-term purchases, including out-of-market purchases. In fact, during January 2001 and into April 2001, the ISO reported that market offers of energy were insufficient to meet the entire estimated requirement for the net short. Consequently, during this period, the division used substantial amounts of real-time out-of-market purchases to serve the net-short requirements. Prices for these real-time purchases were, on average, consistently higher than those for other spot market purchases during this period.

FIGURE 13

The Division's Gross Expenditures
January Through August 2001



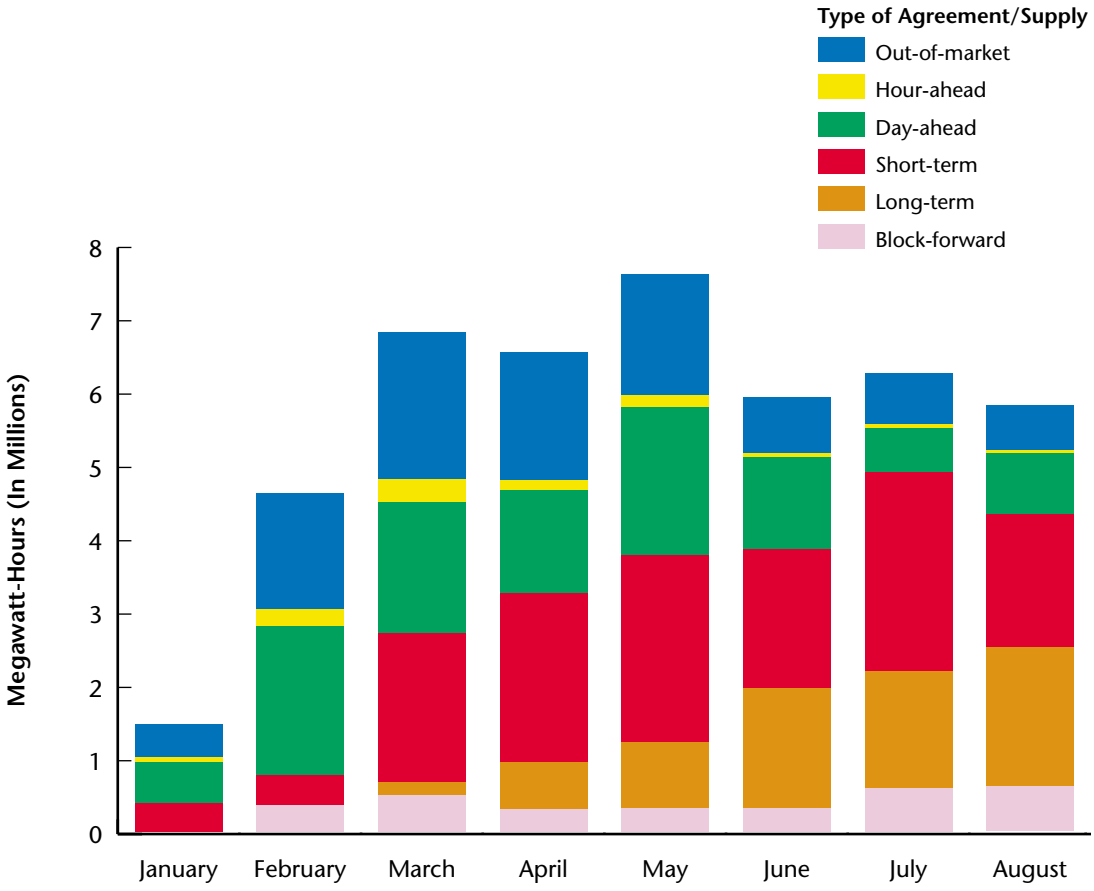
Source: Data provided by the Department of Water Resources.

Short-Term Electricity Prices Began Declining in June 2001

The rate of division spending on short-term energy supplies declined substantially beginning in June 2001. The primary reason for this drop is that prevailing prices for short-term purchases in California decreased by more than half relative to the extraordinary price levels of late 2000 and early 2001. Specifically, spot energy prices in California declined from more than $300 per megawatt-hour in January to less than $38 per megawatt-hour in October, with the greatest decline from the month of May 2001 to June 2001. Figure 14 on the following page illustrates the monthly volume of the division's short-term energy purchases, which include day-ahead, hour-ahead, real-time, and short-term purchases of three months or less in duration. Figure 15 on page 135 presents the monthly average prices of these purchases. The decline in spot market prices for electricity during this period can be attributed to a combination of the following factors:

FIGURE 14

Total Division Energy Purchases
January Through August 2001

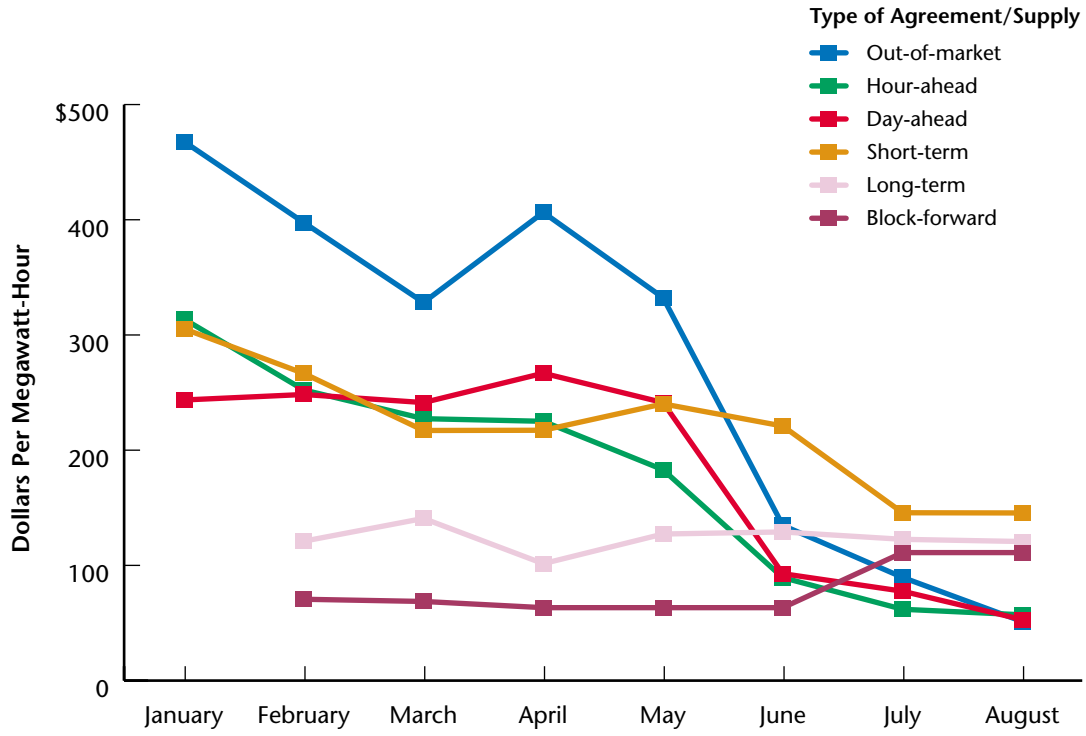


Source: Data provided by the Department of Water Resources.

- **Generator outages declined substantially.** On May 1, 2001, the ISO reported that more than 12,500 megawatts of generating capacity was unavailable. More than 4,000 megawatts of the unavailable capacity was owned by the utilities, including about 3,000 megawatts of nuclear capacity. By the end of May, the total reported unavailable capacity had declined to 8,457 megawatts, of which only 1,760 megawatts was owned by the utilities. As of July 1, total unavailable capacity declined further to 3,227 megawatts. Of this amount, the unavailable generating capacity owned by the utilities stood at 961 megawatts, with virtually all nuclear capacity back on-line.

FIGURE 15

The Division's Weighted Average Purchase Price
Total Energy Purchases for January Through August 2001



Source: Data provided by the Department of Water Resources.

Qualifying facility (QF) capacity, another component of utility-retained generation, showed the same type of improvement. As of April 23, more than 1,660 megawatts of QF capacity was off-line, but by May 14 only about 580 megawatts was reported as unavailable.

- **California natural gas prices decreased considerably.** Monthly average spot prices for natural gas ranged from about $10 to $13 per million British thermal unit (MMBtu) in January 2001. By May 2001 natural gas prices in Northern California had declined to under $5 per MMBtu, while Southern California gas prices were holding at more than $11 per MMBtu. Over the next two months, gas prices declined steeply, especially in Southern California. In July monthly average spot prices were $4.23 per MMBtu in

Southern California and $2.82 per MMBtu in Northern California. Figure 10 on page 124 shows California natural gas prices from January 1999 through August 2001.

- **Demand for electricity declined significantly.** Customer awareness of the electricity crisis, along with customer response to increased electricity prices, reduced electricity demand. Peak loads for May and June 2001 were lower than peak loads in May and June of 2000 by about 10 percent and 14 percent, respectively. Monthly energy consumption also showed similar declines. Compared to May and June of 2000, energy consumption for the same period in 2001 was down 11 percent and 12.4 percent, respectively.

- **New generating capacity entered the market**. New generating capacity started coming on-line in June and July, and this development helped to lower electricity prices further. By the end of June, the 338 megawatt Sunrise Power project was on-line. By the end of July, four more new facilities joined Sunrise. In total, 1,683 megawatts of capacity had entered the market by July 2001.

- **Prices for NOx emission allowances declined.** In Executive Order #01-03 (February 20, 2001), the governor placed into effect many changes to the market in which generators have a means to trade emission allowance credits, retroactive to January 11, 2001. These changes included dividing the market into two groups: electricity generators and nonutility facilities. This division in the market prevented the demand for NOx allowances from other industries, such as manufacturing or refining, from affecting the cost of electricity generation. NOx allowance prices for electric generators were then capped at $7.50 per pound going forward.

- **The division reduced California's reliance on spot market purchases**. New contracts negotiated by the division's long-term contract team during February and March 2001 began to deliver noticeable amounts of energy beginning in April 2001. The division also entered short-term arrangements from several weeks to several months in duration. Together, these purchases served to reduce the residual energy requirements that the division needed to purchase from the spot market. As a result, the division was in a better position to negotiate prices and terms for its remaining short-term purchases.

Each of these factors apparently played a part in the decline of prices in the spot market. It is difficult to quantify the factors' relative contributions because several showed significant improvement during the period from May through June, when spot electricity prices began to decline.

The decline in the division's spot market purchases during the summer of 2001 was also aided by a significant decline in the net-short position.

This decline in the division's spot market purchases during summer 2001 was also aided by a significant reduction in the net-short position despite seasonal increases in electricity demand. A primary reason for the decline in the net short was that utility-retained generation increased substantially, with several large nuclear units returning from outages (both planned and unplanned), and with QF generation returning to service after extended outages due to financial problems. In addition, the volume of direct access load (customer load served by alternative retail suppliers) increased rapidly during the summer. The department's consultant estimates that direct access load increased between the second and third quarters of 2001, resulting in an average of 800 fewer megawatts that the division was required to purchase.

Future Short-Term Expenditures Will Constitute Only a Fraction of Those for 2001

Most of the division's expenditures in 2001 were for short-term energy supplies, and only a limited fraction of 2001 expenditures related to long-term contracts. Projections indicate that for 2002, this relationship will reverse as the division purchases smaller volumes of short-term energy at much lower prices. Specifically, market data and projections indicate the following:

- Spot market energy prices in California have declined greatly since May 2001. During recent months, spot prices have mirrored the spot prices from the first several years of the California Power Exchange.

- Recent broker quotations for forward power purchases indicate that purchases of round-the-clock energy for terms of 1 to 3 years are available under $40 per megawatt-hour. These price levels are consistent with spot prices in more recent months and indicate that the division will probably face significantly lower prices for short-term purchases than it did on average in 2001. The department's November 5, 2001,

revenue requirement forecast confirms this outlook, projecting an average price of roughly $35 per megawatt-hour for short-term purchases in 2002.

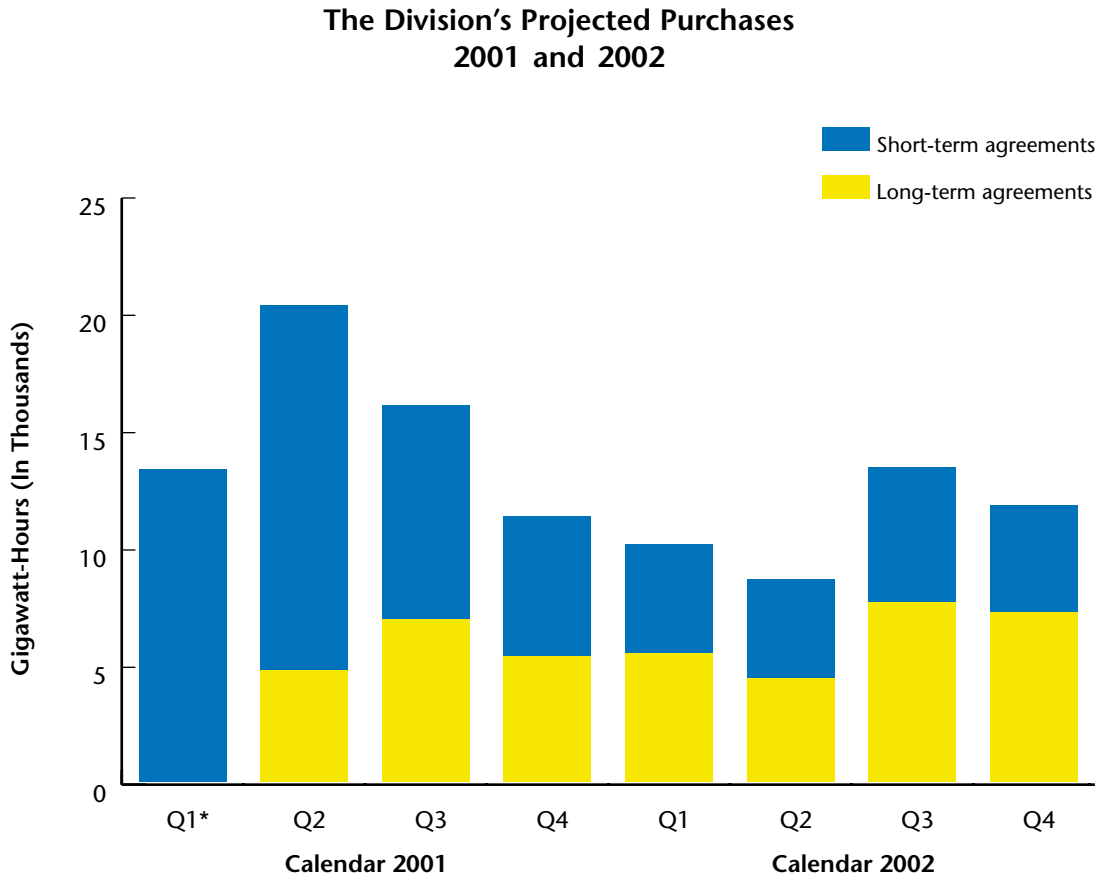
- Fewer short-term purchases will be needed through 2002 to fill the investor-owned utilities' net-short position, as deliveries from long-term contracts increase and as existing contracts provide a full year of energy deliveries.

- Increases in direct access load (load supplied by other energy retailers), which occurred primarily in the third quarter of 2001, are projected to reduce significantly the net-short position relative to actual levels for the first half of 2001.

Because of the expected lower prices and lower volumes, the division projects that its expenditures for short-term supplies in 2002 will represent only a small fraction of the 2001 level. Instead, expenditures for long-term contracts will dominate during the coming year. Figures 16 and 17, which are based on the department's draft of its revenue requirement forecast dated November 5, 2001, illustrate the projected energy purchases and expenditures by the division for long-term contracts and short-term supplies through 2002.

The summary projection in the two figures presents the total estimated requirements and supplies for all investor-owned utilities affected by the power-purchasing program. As we explain in Chapter 1 of this report, the division's long-term contracts are disproportionate for delivery south of Path 15, an important transmission interface. In other words, the need for additional supplies is greatest in Northern California, while the need for additional supplies is smaller (and some surpluses are expected) in Southern California. Therefore, the expected proportion of short-term purchases for Northern California is somewhat greater than these figures show, while Southern California faces a correspondingly lower proportion of short-term purchases and a net surplus in some years.

FIGURE 16



Source: The Department of Water Resources' November 5, 2001, Revenue Requirement Filing.

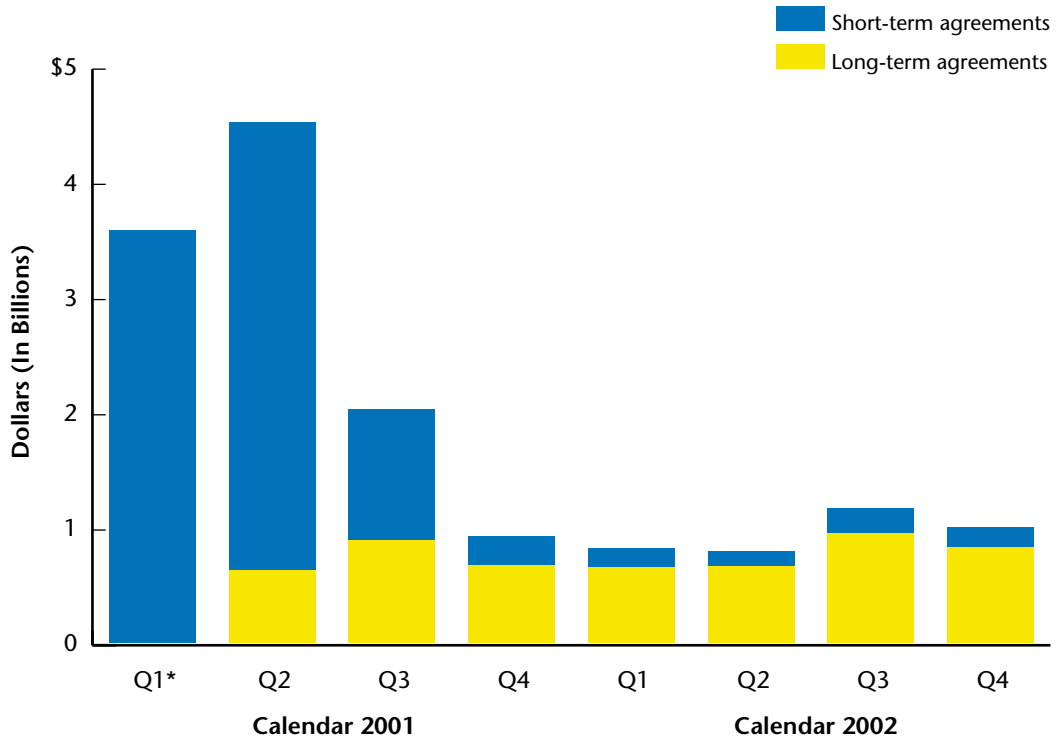
* Q = quarter

The Division Has Significantly Reduced Its Reliance on Daily and Real-Time Energy Purchases

Before the department was assigned the job of purchasing the investor-owned utilities' net-short requirements, almost all of those requirements were purchased in the short-term market. In addition, in late 2000 substantial fractions of those purchases were made in the real-time market. This level of reliance on the spot market had exposed California customers to large swings in short-term market prices and was cited by Federal Energy Regulatory Commission (FERC) staff and the ISO's Division of Market Analysis as contributing to the incidence and magnitude of price spikes in the spot market.

FIGURE 17

The Division's Projected Expenditures 2001 Through 2002



Source: The Department of Water Resources' November 5, 2001, Revenue Requirement Filing.

* Q = quarter

According to the department, the division's short-term purchasing strategy focused on reducing from early 2001 levels the State's day-ahead and real-time purchases. The division sought to achieve this reduction by making new short-term purchases of 1 week to several months in duration or purchases of multiyear agreements like those negotiated by the long-term contracting group. However, according to the department, it was not able to implement its strategy to reduce its reliance on the spot market as swiftly it would have liked due to funding limitations through the month of February. During January and February, most division purchases were in the day-ahead and hour-ahead markets and out-of-market. No long-term contracts were in place yet, and few purchases were made more than 1 day ahead of delivery. During February and March, the division began to make significant progress toward its goal of reducing reliance on the spot market by making forward purchases of several weeks to several months in duration.

During February and March 2001, the division began to make progress towards reducing reliance on the spot market by making purchases of several weeks to several months in duration.

Figure 14 on page 134 presents a monthly breakdown of the division's energy purchases in terms of short- and long-term agreements. Total division purchases climbed from January (a partial month) through May 2001. This increase reflects a seasonal rise in electricity demand, along with a significant amount of utility-retained generation that was unavailable. Total division purchases declined during the summer months. As we noted earlier, the investor-owned utilities' net-short position declined noticeably during the summer months due to a combination of higher production of utility-retained generation, moderate electricity demand, and increased retail access.

Beginning in March the division significantly increased the short-term energy purchases it was making more than 1 day in advance of delivery. Initially, most of the term purchases were monthly contracts. During May and June 2001, the division purchased about 1,950 megawatts for delivery through the third quarter (July through September). Energy from purchases negotiated by the long-term contract team began to appear in noticeable volume during April. These longer-term purchases increased to an average of about 28 percent of the division's total purchases during the summer (June through August). Overall, the volume of the division's purchases in the spot market and real-time market volume has declined significantly, both in terms of monthly megawatt-hours and as a percentage of total purchases, with much of the change attributable to purchases of new short-term agreements with longer durations, such as monthly or quarterly terms.

UNSETTLED PURCHASES AND DELAYED PAYMENTS TO SELLERS MAY JEOPARDIZE FUTURE AVAILABILITY OF ADEQUATE POWER IN THE ISO'S REAL-TIME MARKETS

Under a recent FERC order, the failure of the division and the ISO to reach agreement on how to facilitate the payment of power purchase obligations that are long outstanding may disrupt the future supply of available power in the ISO's short-term markets. In November 2001 FERC found that in the power delivery system, power suppliers must deliver power to the grid when ordered by the ISO, but that obligation is based on a must-pay obligation to the creditworthy party that backs the power purchase transaction.

If past due bills for purchases are not paid, sellers may not provide power to the ISO real-time market.

The division has initiated efforts to support the ISO and its markets to ensure an adequate supply of energy and reserve power needed by the ISO for system reliability purposes. An agreement between the department and the ISO suggests that, effective January 21, 2001, the division had agreed to procure power through bilateral transactions in response to needs identified by the ISO and to purchase power for the ISO's "real-time balancing adjustments to meet the changing load requirements of the PG&E and SCE service areas." In April 2001, because the ISO did not appear creditworthy, the department assumed financial responsibility for all purchases by the ISO to provide system reliability and reserve power based on bids or other offers that the department determined to be reasonable.

However, a dispute has developed between the generators, the ISO, and the department regarding payments for power purchases for which the division has been identified as a creditworthy backer. For sales of power in the ISO's markets, the ISO receives invoices from sellers and payments from buyers, and its serves as a clearinghouse for the transactions. In a complaint filed with FERC on September 10, 2001, a group of California generators alleged that they had not received payment from the ISO for services rendered across several months and for which the division has been identified by the ISO as a guarantor. The ISO has not invoiced the department for the purchases; instead, the ISO invoiced the investor-owned utilities for the purchases. In its filing to FERC, the ISO stated that although the department is the guarantor, it is not the debtor under the ISO settlement procedures. FERC disagreed and ordered the ISO to bill the department for the purchases. The department states that it must have transaction data that identifies the suppliers for which it must pay and the amount of the purchases, but the ISO has not provided the data due to concerns about the confidentiality of the market data.

THE DEPARTMENT HAS ALSO RESOLD POWER MOSTLY TO BALANCE ITS REAL-TIME TRANSACTIONS

In the bulk electricity network, the total energy generated must always equal the total system load. However, it is not possible to predict power requirements precisely a day or even a few hours in advance because factors such as weather, generator outages, and fluctuations in production from intermittent generating units can vary. Consequently, if the combined energy purchases made by the division in any hour exceed the actual net-short

position of the investor-owned utilities, the difference must be sold on a real-time basis—known as a resale. Electric systems worldwide require real-time balancing transactions of this type.

The division has resold unneeded power it purchased mostly to adjust estimated real-time demand to actual real-time demand.

Similarly, in developing a portfolio of long-term power sources, electricity purchasers generally cannot exactly match the power loads with supply at all times. For example, a utility with a supply portfolio that is balanced on an annual average basis may need to make short-term resales during some conditions (such as light load periods or high hydro production) and make short-term purchases at other times (such as periods of high outages).

While some amount of short- and longer-term resale is expected in most large utility systems, large volumes of resales can be problematic. For example, at any given time the price at which a market participant is able to buy energy exceeds the price at which it is able to sell by at least some amount. It is therefore desirable to minimize instances of offsetting short-term transactions, such as the purchasing of a monthly energy contract and the rapid reselling in the spot market of a substantial portion of that contract. Further, when long-term supply commitments turn out to be surplus and are resold, the net power supply cost increases if prevailing market prices decline after the long-term purchase is made.

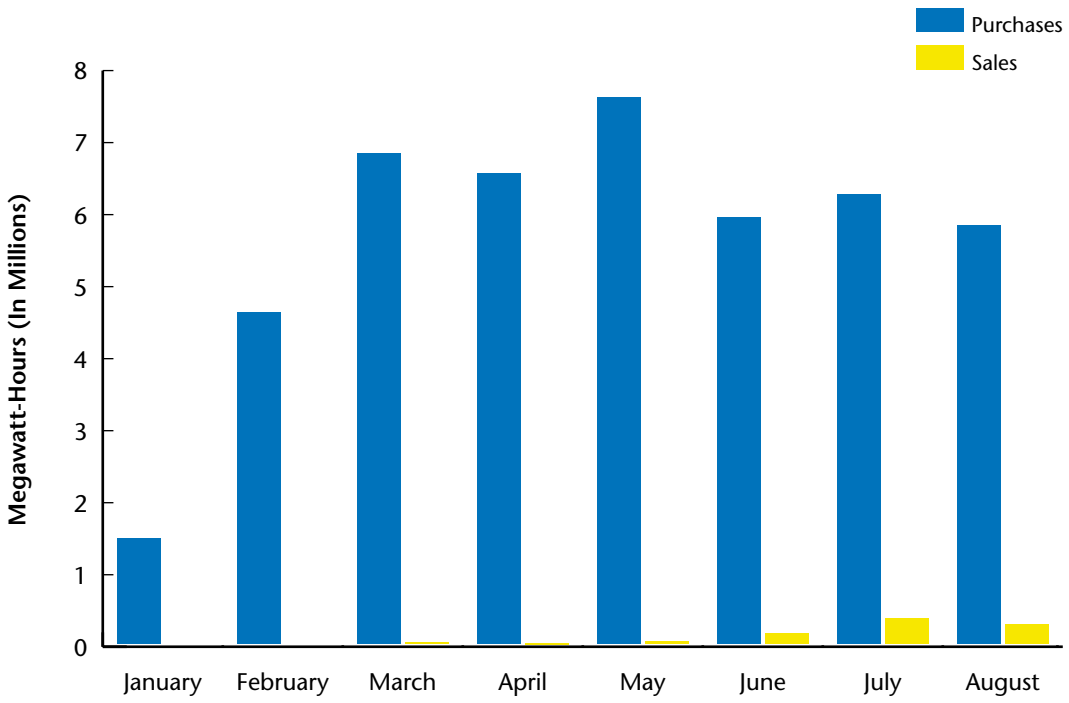
Resales of Surplus Energy to Date Were Limited and Primarily Matched Real-Time Power With Real-Time Demand

Since the division began with a large net-short position and essentially no long-term contracts, the vast majority of its short-term transactions during 2001 have been purchases. In fact, division staff reports that for several months it was often difficult to find sufficient offers to serve the residual net-short position in the day-ahead market. The division has, however, made some resales during 2001. According to the department, real-time resales (as well as purchases) occurred primarily when the actual loads or generation in the ISO's control area, including loads and generation not associated with the investor-owned utilities, turned out differently from their scheduled values. Figure 18 on the following page presents the volume (megawatt-hours) of division resales and purchases by month between January and August 2001. As the figure shows, the division made no resales for the first several months of its operation. The first division resale of energy was in March, and resales increased to more significant volumes during July and August. During each

month, the total resales were small relative to the total volume of division purchases. The August volume of division resales represented an average of about 317 megawatts across all hours of the month and ranged as high as about 35,200 megawatt-hours for one day.

FIGURE 18

Division Energy Sales Compared to Purchases
January Through August 2001



Source: Data provided by the Department of Water Resources.

According to the energy scheduling and trading manager, the division transacts in short-term purchases, which include monthly and quarterly purchases, and also transacts in the day-ahead and hour-ahead markets to meet the estimated net-short position. The division does so based on the best available information provided by the investor-owned utilities during the trading periods for the respective markets. Since June 2001 these markets have generally had sufficient offers from suppliers to fill the estimated net-short position.

Although the long-term contracts discussed in Chapter 1 have begun to deliver significant volumes of energy, the total volumes have amounted to only a limited fraction of the net-short position for which the division is responsible (see Figure 14 on page 134). During 2001, the division has almost always needed additional supplies above those provided by its long-term contracts. When the division has had significant surplus energy, it is because the surplus has arisen from the combination of the division's long-term purchases and additional short-term purchases that have exceeded the actual net-short requirements.

Further, according to division records, a high percentage of resales in August 2001 were in the real-time market because of the ISO's instructions that the division match the real-time power in the delivery system to the real-time demand from consumers. For example, in August the division sold a total of about 276,000 megawatt-hours. The division indicates that of this total, only about 40,000 megawatt-hours were sold by the division in the day-ahead or hour-ahead markets to balance the estimated net-short position of the investor-owned utilities. The remaining 236,000 megawatt-hours were sold in the real-time market at the instruction of the ISO. According to the trading manager, the fact that most energy was sold in the real-time market at the instruction of the ISO appears to implicate many other reasons for the resales other than the division's procuring excess energy. She explains that the division's scheduled day-ahead and hour-ahead purchases have been in balance with the utilities' forecast net-short position.

The Causes and Implications of Real-Time Transactions Are Not Clear

According to the trading manager, the division has been unable to conduct a detailed analysis of the causes of real-time sales and purchases because ISO information, such as generator deviations from scheduled delivery, retail customers' meter data, and delivery path congestion, is not available to the division. Nevertheless, the primary causes for real-time sales and purchases appear to be a combination of the following:

While the division has been unable to investigate the causes of real-time power sales, they appear to be the result of a combination of factors.

- **Electricity demand and generation supply have routine variations.** It is not possible to forecast the precise electrical requirements of a large utility. Weather changes over the course of a day can cause actual electrical demand to exceed or fall below the day-ahead forecast, generating units can

unexpectedly trip off-line or return to service, and unexpected events in the transmission system can require adjustments to dispatch or purchase schedules. Similarly, the California electricity system features significant wind capacity, for which actual hourly production can be intermittent and which can be difficult to forecast on an hourly basis. Electric utilities throughout the world face such real-time variations in supply and demand.

- **Investor-owned utilities may provide the division with an overestimated net-short position**. Since December 2000 the FERC has imposed a significant penalty on load serving entities (including the investor-owned utilities) when they do not schedule at least 95 percent of their anticipated capacity needs before real time. There is no corresponding penalty for scheduling more than 95 percent. As a result, it would be rational for California's investor-owned utilities to give the division overstated forecasts of the net-short position to ensure that real-time purchases do not exceed the threshold and avoid the risk of incurring an imbalance penalty. According to the division's consultant that serves as its systems analyst, the division has not performed detailed analyses to determine if this condition exists. However, the division is aware of discrepancies between the actual data that the investor-owned utilities believe represent their loads and the data used by the ISO. Discussions are underway to resolve these data problems.

- **Generators may not honor schedules and ISO dispatch instructions**. The ISO has expressed concern over increasing instances in which generators have not honored ISO instructions to increase or decrease the amount of energy being generated, particularly during July and August 2001. In addition, the division's systems analyst indicated that generators in the California market apparently may vary their production from advance schedules. The division has not determined the extent to which this type of generator behavior is contributing to real-time imbalances between forecast and actual electricity demand (imbalances). Only the ISO has the data to determine the extent of this activity, if any.

- **The division may receive poor forecast information**. Because the division's target is a forecast rather than reality, significant real-time imbalance energy transactions can be required to balance the ISO system. Such variances could come about from inaccurate forecasts of demand or of utility-retained generation, or both. The division screens the

utilities' net-short forecasts to see whether they are reasonable, but uses those forecasts as the primary target for day-ahead and hour-ahead trading.

According to the systems analyst, the division has not been able to assess quantitatively the relative contributions of these factors toward hourly imbalances, primarily because such an analysis requires confidential data from market participants data (including hourly load and generation schedules and comparable actual figures) to which the division does not have access. The division's systems analyst indicates that the division and the investor-owned utilities have begun an exchange of information designed to improve their understanding of the causes of imbalanced energy. The systems analyst further states that the causes of the imbalances are not readily apparent even to experienced utility personnel. Although it is understandable that a lack of confidential information makes it difficult for the division to obtain a precise comprehension of the factors that drive imbalanced energy transactions, it is unclear whether the division has devoted adequate attention to improving its understanding of this issue by using the available information on utility-owned generation and load forecasts.

The division has not been able to assess contributions of the factors that cause hourly imbalances because it does not have access to confidential market participant data.

The financial implications of resales in 2001 have been small relative to the total division portfolio. This absence of significant repercussions is largely due to the limitations of resale volumes relative to the division's purchases (see Figure 18 on page 144). However, even in a market with relatively stable prices, heavy participation in the real-time market can have significant costs when there is a significant price spread between offers to sell and ones to buy and when real-time energy prices vary significantly from those in other short-term markets. The division needs staff resources to develop a clearer understanding of whether the volume of imbalance energy is problematic from a financial perspective and, if so, what steps can be taken to mitigate it.

Energy Resales by the Department Could Increase Substantially Over the Next Several Years

While resale volumes and their financial importance have been limited so far in 2001, their importance appears likely to increase over the next several years. As we discuss in Chapter 1, the department's consultant believes that the division could experience sustained surplus conditions, particularly in Southern California, during the fourth quarter of 2003 through the fourth quarter of 2005. The division may therefore have to

resell significant amounts of energy in order to match the net-short position on average across a season or a year. Even if energy from the division's long-term purchases roughly equals the net-short position on an annual basis, the large fluctuation of the net-short position and the high amount of electricity the division must buy from its long-term contracts will probably result in significant resales of electricity. These results will more frequently occur during periods of light electricity demand or high production from generation owned by the investor-owned utilities.

The amount of the division's surplus energy could increase in the future due to long-term purchase commitments and a declining net-short position.

In addition, the prospects for resales by the division have increased significantly in recent months because substantial numbers of retail customers served by the division and the investor-owned utilities chose alternative generation suppliers during the third quarter of 2001. The department's consultant estimates that once all of these direct-access load requests have been processed, the direct-access load will reduce the net-short position by about one-third during the fourth quarter of 2001. If direct access were to continue at these levels, the net-short position would be significantly lower than previous division planning analyses depicted, and substantial volumes of resale energy would be likely for several years.

The financial consequences of future division resales are uncertain because they will depend on actual market prices when the surplus is sold. However, it is likely that the average prices that the division receives for resale energy will be lower than the average prices it pays under its long-term purchase contracts. As we discussed earlier in this chapter, market fundamentals (such as fuel prices and the balance between supply and demand) have improved noticeably since most of the long-term contracts were negotiated, and short-term energy prices have dropped substantially.

MORE SYSTEMATIC ANALYSIS OF SHORT-TERM TRANSACTIONS IS NEEDED

As we explained earlier in this chapter, the division has entered into short-term energy agreements of up to 3 months in duration and up to 2 quarters in advance of delivery. While these purchases have had the desirable effect of reducing the division's reliance on the spot market, it appears that the division could improve its decision-making process with respect to identifying which forward purchases to make and how much energy to purchase.

The Department's Processes for Making Decisions Regarding Forward Market Purchases Are Still Under Development

According to the department, the division is still developing its procedure for making forward short-term purchases, which the contracts committee directs. Further, the department indicates that the current analysis focuses on the estimated net short, as estimated by one of the division's energy consultants. The consultant conducts a deterministic analysis to estimate the average net-short position monthly and quarterly for peak and off-peak hours. The estimated net-short information is given to the division's scheduling group and the contracts committee. Broker quotations are used to estimate the price at which the division could purchase contracts of various durations. The contracts committee discusses the market outlook and seeks a consensus as to what—if any—forward purchases the division should make. If agreement is reached, the desired purchase amounts go to the division's scheduling group for execution.

The outlines of the division's transaction planning process make sense, but the magnitude of the transactions that the division is making appears to warrant a greater level of sophistication. For example, minutes of the contract committee do not indicate that the division has developed its own "market view" of future spot market prices or that it has rigorously examined the appropriate fraction of its portfolio that should be provided by spot market purchases, with the exception of real-time purchases. Similarly, it is not apparent that the division's selection of short-term transactions has considered quantitatively the range of potential variance in the net-short position. Examination of alternative outcomes is very useful in California because both the residual net-short position and regional market prices can vary substantially based on factors such as fluctuations in hydro, weather, and generating unit availability. In addition, some adverse outcomes (such as a high net-short position combined with high market prices) are likely to occur together. Uncertainty analysis can also be particularly informative for the division because although the division must purchase about one-third of the investor-owned utilities' energy requirements, it must be prepared to absorb all of the variance in those requirements.

Because the division's net-short position can be significantly affected by variances in demand and production, it must perform sophisticated analyses to support its short-term purchases.

The division has produced a Draft Statement of Short-Term Energy Procurement Limits. This document is a positive step, but further attention is warranted. In the draft statement, the division describes its short-term trading limit structure as one component of a broader risk-based transaction policy that is

under development, and it notes that volume and price uncertainty need further evaluation. Without these steps, the division will risk not having a fully informed understanding of its energy needs and its cost exposures, and thus its short-term purchase strategy has the potential to be less than optimal.

The Net-Short Analysis Will Become Increasingly Complex as the Department's Dispatchable Long-Term Contracts Take Effect

When the division was assigned the job of purchasing the net-short position, production by utility-retained generation was much less than the total energy requirements of the investor-owned utilities, and the utilities were relying heavily on short-term energy purchases. As a result, the division's primary goal with respect to transaction analysis during 2001 has been to determine how much energy to purchase and when. Although the division has purchased substantial energy during 2001 under monthly, quarterly, and long-term contracts, the vast majority of energy from these sources has been delivered on fixed schedules (for example, 24 hours per day, 7 days per week, or 16 hours per day, 6 days per week). Once it made those purchases, the division faced only limited choices as to the amounts of energy that were delivered.

The flexible terms of the division's long-term contracts will increase the complexity of its decisions regarding short-term purchases.

This situation will change greatly in 2002, when dispatchable contracts become an important part of the division's portfolio. Specifically, long-term contracts for about 2,900 megawatts of dispatchable energy will take effect in 2002, with contracts for about 2,700 megawatts of dispatchable energy available during 2003. Under these contracts, the division pays a fee to the sellers to reserve a specified amount of power and will have the ability to choose (within the contract parameters) how much energy should be delivered and when. This flexibility will allow the division to take delivery of contract energy when spot market prices are more expensive than the contract energy price and to purchase spot market energy when it is less costly to do so. The presence of the dispatchable contracts may also improve the negotiating position of the division in the short-term market.

These choices will, however, significantly increase the complexity of the net-short analysis, because deliveries under these contracts will become an added variable. The net-short position will depend not only on electricity demand and production by utility-retained generation but also on wholesale market prices. In order to maximize the benefit of this flexibility and to determine when to

use its dispatchable contracts, the division will need to conduct additional analyses that explicitly represent the flexibility inherent in the contracts and simulate the choices between contract energy and spot market energy. Effective portfolio analysis should also incorporate uncertainty analysis, explicitly testing the effect of alternative outcomes for key planning parameters (such as electricity demand, weather, hydro production, and fuel prices) on the net-short position and the cost of the total portfolio.

The division's Contract Management Protocol (protocol) outlines the need for the division to perform a number of key functions with respect to contract management, and the protocol outlines processes to accomplish them. These functions include the portfolio risk analysis and dispatch functions just listed, and they also encompass other operational tasks, such as estimation and purchasing of fuel requirements and significant steps to ensure that suppliers are meeting the terms and conditions of the contracts. The protocol is a positive step, but the division and its consultant recognize that organizational improvement will be needed with respect to the management of the long-term contracts. The protocol is self-described as a "skeletal framework" of the contract management process. It recognizes that the division's risk management framework will be developed during the coming months and that "augmentation and strengthening at all levels and management support are needed to invest in the necessary systems, tools, and personnel to carry out this function effectively."

Given the magnitude of the division's contract portfolio, including dispatchable contracts, division management will need to maintain a focus on enhancing the organization's objectives and specific methods for contract management. The contract management needed includes such tasks as portfolio analysis with the objective of minimizing the cost and risk of the total division portfolio, along with the contract-specific monitoring and management tasks described in Chapter 4 of this report and in the protocol. As we discuss earlier in this chapter, staffing levels for contract management and portfolio analysis are also a concern. These tasks are about to expand in scope and complexity, and some of them require specialized skills. The protocol explicitly states that the functions will be quite challenging given division resources, and it states that "[the division] is constantly juggling priorities and assignments to address critical problems as they arise." This assessment is consistent with our observations during this audit. It will be important for the division to receive

Well-designed portfolio analysis can meaningfully reduce the total cost of power to California utility customers, and its absence can unnecessarily increase costs.

adequate support—whether from internal staff or consultants—to perform the tasks associated with contract management and portfolio analysis. Well-designed portfolio analysis can meaningfully reduce the total cost of power to California utility customers, and its absence can unnecessarily increase costs.

Finally, the division's protocol appears to assume that the division will be responsible for managing its portfolio of long-term contracts in the long term and in the context of a least-cost dispatch. It is not clear, however, that the division will be responsible for the latter role after 2002. It would be possible for the division to retain overall management of its long-term contracts while assigning responsibility for portfolio analysis and dispatch of the division's long-term contracts to the investor-owned utilities or another entity. The makeup of the division's staff, and its duties during 2002, will depend to some degree on which options the division pursues. Timely resolution of this question will help to ensure that the division's organization develops to handle division responsibilities or (in the event that the dispatch responsibility transfers to another entity) to enable a smooth transition.

BETTER OPPORTUNITIES EXIST FOR COORDINATION BETWEEN THE DIVISION'S SHORT-TERM TRANSACTIONS AND UTILITY-OWNED GENERATION

The division is presently responsible for purchasing the net-short position of California's investor-owned utilities. This position varies considerably daily and seasonally according to variations in production from the utility-owned generation and qualifying generation sources (renewable and co-generation facilities) and, to a lesser extent, on variations in utility-purchased power contracts.

The Department's Net-Short Requirements Vary With Changes in Power Supplied by Utilities

The utility-owned generation is an important part of the California power supply, providing more than 12,000 megawatts of generating capacity and roughly 30 percent of California's annual energy requirements. As Table 9 shows, the largest components of the utility-owned generation are about 5,000 megawatts of hydroelectric capacity (much of which has at least some capability to store water for later discharge) and about 4,800 megawatts of nuclear capacity. The nuclear units, and those "run of river" hydro units that lack storage, are essentially economical to

operate whenever they are available. In contrast, it is not always economical to operate the coal units and the storage hydro units at full output, so development of a least-cost schedule requires analysis and judgment.

TABLE 9

Utility-Owned Generation (in Megawatts)

Fuel Type	Pacific Gas & Electric	Southern California Edison	San Diego Gas & Electric	Totals
Coal	0	1,639	0	**1,639**
Gas	579	0	0	**579**
Hydro	3,890	1,130	0	**5,020**
Diesel	0	9	0	**9**
Nuclear	2,160	2,204	430	**4,794**
Totals	**6,629**	**4,982**	**430**	**12,041**

Utilities typically make these decisions with the objective of minimizing their total cost of generating and purchasing power, subject to the operating constraints of the generating units. The decisions are typically based on comparisons of the investor-owned utilities' generation costs to spot market prices, assessments of spot prices across the hours of a day or week, and comparisons of revenues (or savings) that could be achieved in the energy market to those available in the ancillary service markets. To minimize the total cost to serve California's utility customers, the division should utilize a least-cost dispatch involving the utility-retained generation and the division's short-term purchases. To date, this decision making has not occurred.

Coordination Between the Department and the Utilities Can Lower Prices to Retail Customers

The investor-owned utilities and the division have been discussing ways to coordinate the dispatch of all resources for a least-cost solution. However, the division and the utilities have not yet been able to coordinate their efforts primarily because allocation of costs is a major obstacle. According to the systems analyst, since the division was formed, the investor-owned utilities have planned the dispatch of the power from their generating units independently and have provided the resulting hourly schedules to the division each day. The schedules look ahead to the

The department does not know from day to day whether the utilities might be able to adjust their generation to reduce the department's power costs.

following day and the following week. The division's trading personnel do not know the details of how the utilities develop the generation schedules, nor (in the case of Pacific Gas & Electric) do they know the specific generating units that are scheduled to generate in any particular hour. As a result, the division essentially takes the utilities' generation schedules as a given for the purpose of its daily transaction activities. Thus, the division does not know from day to day whether a utility might be able to increase or decrease output from a thermal unit, rearrange its hydro generation schedule to minimize the division's market purchase costs, or provide ancillary services at a lower cost than the prevailing market price.

Ways in which a coordinated dispatch could provide savings include the following:

- **Minimizing the cost of the division's daily and hourly purchases by shaping the hourly schedule of utility hydro units.** In particular, the division finds that spot market prices for standard blocks of energy (such as 16 hours on peak) tend to be noticeably lower than for "shaped" energy purchases that provide different volumes in each hour. Many of the utilities' hydro units have significant hourly flexibility, and the division believes that careful coordination of the hydro schedules would allow the division to maximize its purchases of standard energy blocks and minimize the more expensive shaped purchases.

- **Generating lower-cost reserve power using hydro units.** In general, a storage hydro unit can maximize the value of its energy output by generating at full output during the hours when the market value of its energy is highest. Alternatively, the unit may be able to generate the same amount of energy by operating for a longer period at less than full production while also self-providing needed reserve power (ancillary services) for unscheduled real-time power needs. Because hydropower is cheaper to produce than other sources of reserve power, such as gas-fired power, the use of hydropower in this way can minimize the total cost of energy and ancillary services. The division does not know how often the utilities' hydro units are used to provide ancillary services, but this capability is a potential source of additional savings.

- **Reducing thermal unit production during periods of low energy market prices**. If the incremental variable production cost of a thermal generating unit exceeds spot market energy prices, as might occur during weekends or at night, the least-cost option may be for the utilities to reduce the unit's production and to replace the energy with spot market energy purchased by the division. While high spot market prices made this situation unrealistic during the first half of 2001, it appears much more realistic in the future.

The systems analyst and department consultants believe that a coordinated dispatch could achieve meaningful savings; however, they do not have a firm understanding of the magnitude of the savings that such a dispatch could attain. A division analysis of its actual purchases for a recent day suggested that a coordinated dispatch of PG&E's hydro resources could have reduced the division's purchase costs by about $48,000. If this level of savings were extrapolated to an annual basis, this dispatch of hydro energy would translate to annual savings of about $17.6 million. Although the division's illustration represents only a single sample day and might therefore overstate the potential long-term savings, it does address the potential that large savings could be achieved from coordinating energy and ancillary service purchases. The division does not have the information it needs to determine the extent to which the utilities are using their generation to provide ancillary services or whether that use is optimal.

If we take into account the several potential mechanisms for savings, it seems safe to say that improved coordination of utility-owned generation could potentially reduce the cost of power for utility customers by tens of millions of dollars per year. This level of savings is not large in the context of the total division budget, but it clearly warrants a significant effort.

According to the systems analyst, a key reason that the division does not clearly understand the magnitude of the savings that it could achieve through coordination of utility-owned generation is that the utilities have not provided the details of their generation operations, such as hourly scheduled quantities and the rationale and analysis that they are using to set those schedules. It is also unclear whether the division has devoted sufficient time and resources to resolving the issue. Over many months, the division has conducted a periodic dialogue on this subject primarily through telephone calls and meetings with the utilities. While utility personnel have expressed a willingness to

coordinate the operations, the dialogue has not produced an understanding of how the utility-owned generation and division operations should be coordinated.

The department and the investor-owned utilities have not reached a broader agreement addressing the sharing of information and the allocation of costs.

According to the division's systems analyst, a primary reason for the lack of an agreement is that the division and the investor-owned utilities have not reached a broader agreement addressing the sharing of information and the allocation of costs. More fundamentally, the current utility retail rate structure does not appear to provide the utilities with an incentive to participate in a least-cost dispatch, and under some circumstances it may effectively do the opposite. The reason for this situation is that the utilities' retail generation sales are tied directly to the amount of power they generate, meaning that reduced generation results in the utilities selling less energy. Suppose, for example, that a least-cost dispatch with the division were to reduce generation by a utility—for example, by reducing production from a thermal unit or by operating a hydro unit so as to maximize the provision of ancillary services—relative to the utility's current generation schedule. By reducing its generation, the utility would reduce its retail kilowatt-hour sales in the particular month. To the extent that the utility's retail generation rate exceeds its variable cost of producing the energy, the utility would achieve lower net revenues, at least in the short term.

As of September 2001, the California Public Utilities Commission (CPUC) had not explicitly addressed the retail rate treatment of utility-owned generation and how utility generation costs are affected by the new role of the division. Neither the utilities nor the division appear to have proposed a solution to the CPUC.

According to the systems analyst, looking forward, the division believes that an achievable first step for coordinating utility-owned generation would be to adjust the scheduling of the utilities' hydro facilities in instances in which shifting production among hours would not reduce the total energy production. The hope is that because this step would not affect the total amount of the utilities' generation or their net revenues, the step could be achieved without a more comprehensive agreement. Additional steps that involve reducing generation by the utilities may be more challenging because they would reduce generation sales. In addition, division staff has noted that the division may be legally prohibited from purchasing ancillary services directly from the investor-owned utilities. We have not evaluated whether such a prohibition exists. ■

CHAPTER 4

A Strategic Plan for the Future of the Power-Purchasing Program Is Now Needed

CHAPTER SUMMARY

The problems that we identified in the implementation of Assembly Bill 1X (AB 1X) by the Department of Water Resources (department) arose, in part, because the Legislature gave the department its new mission in the midst of the power crisis, and the department had too little time to plan and staff adequately for its new responsibilities. Now that the crisis has eased, the Legislature and the governor should consider how best to serve consumers' power requirements over the long term and how best to manage the costs and mitigate the risks of the power contracts for the State. This process should result in a comprehensive strategic plan that would determine whether the department should continue to administer any or all aspects of the Purchase and Sale of Electric Power Program (power-purchasing program) and develop a specific set of plans for improving the department's current operations for the functions that it will retain. This plan will be necessary whether the power-purchasing program remains at the department, transfers to a separate state agency, or moves to a different type of governmental entity. The Legislature will also need to consider whether the department's present authority contained in AB 1X needs to extend beyond January 1, 2003, to allow time to resolve present uncertainties that affect these decisions. When developing this plan, decision makers will need to evaluate relevant factors, including the following:

- AB 1X, a short-term measure designed to address the immediate crisis, must be replaced with a comprehensive long-term power-purchasing plan.
- The future management of the existing power contracts cannot be transferred easily to other entities.
- Key issues must be resolved concurrently with the development of the strategic plan.

- The entity administering the power-purchasing program must have the ability to carry out the full functions of a power-purchasing program of this scale.

- The department's responsibilities remain substantial; not the least of which is now managing a $42.6 billion contract portfolio to minimize legal and cost risks to ratepayers.

- The department needs to make a substantial effort to improve its internal capabilities and operations so that it can effectively administer the program.

AB 1X, A SHORT-TERM MEASURE DESIGNED TO ADDRESS THE IMMEDIATE CRISIS, MUST BE REPLACED WITH A COMPREHENSIVE, LONG-TERM POWER-PURCHASING PROGRAM PLAN

When AB 1X was enacted on February 1, 2001, the severity of the crisis necessitated immediate action. In providing the department with the authority to purchase electricity for 2 years, the statute recognizes that the crisis would not be resolved overnight. In limiting the department's authority to 2 years, the statute recognizes that giving the department the purchasing role is not necessarily a long-term solution.

It is now time for decision makers to step back and develop a comprehensive plan for the future of the State's power supply system and for the department's function as a part of that plan. The immediate power crisis has now eased. With just over a year remaining on the purchasing authority, the department and the State are at a crossroads. The crisis that existed during the development of AB 1X and in its implementation to date have afforded the department or others little time to develop a reasoned plan for the conduct of this function.

The department is not yet well positioned to effectively serve as the State's sole power buyer for the investor-owned utilities.

The department is not yet well positioned to serve effectively as the State's sole power buyer for the investor-owned utilities. As earlier chapters discuss, the department is still developing staff and infrastructure to conduct its power-purchasing functions. The department must now spend considerable resources to develop more fully its ability to carry out its purchasing role over the ensuing year and its contract management role thereafter. In addition, if the department's purchasing role ends by January 2003, it must engage in an orderly transition of that role to other

entities. After that date, and, indeed, even after the investor-owned utilities return to a creditworthy status, some entity must manage the long-term contracts and other associated tasks, such as the periodic calculation of the revenue requirement to cover the costs of those contracts. Thus, the strategic plan should identify which entities will have these responsibilities.

If the investor-owned utilities are not creditworthy by the time the department's present power-purchasing responsibility expires, the department, or some other entity, must continue to purchase the net short, which is the difference at any one time between the power that the three investor-owned utilities supply from their generation and reserves and the total consumer demand for power. The strategic plan will need to consider the likelihood that one or more investor-owned utilities will not be able to purchase the net short after 2002. Such a situation would affect, among other things, the way in which the department approaches its tasks in the coming year as well as the resources that are made available to the department. Thus, the planning needs to take place as soon as possible. This planning would allow the department to prepare for its power-purchasing role to continue beyond January 1, 2003, for termination of its role, or for transfer of the department's power-purchasing authority to another entity. Preparations need to occur soon to assure continuity and to prevent another abrupt transfer of responsibility for the power-purchasing function. AB 1X does not furnish long-term guidance for the power-purchasing program or for the department, nor does it provide for an orderly transition to a long-term plan. As we explain elsewhere in this audit report, the State has incurred substantial costs because of the crisis. Various inefficiencies, which necessarily came with the department's abrupt assumption of the power-buying role, escalated these costs. The department has just one more year of power-purchasing authority, but the State has no clear plan for purchasing power for consumers after 2002.

Some actions are needed soon to assure continuity and to prevent another abrupt transfer of responsibility for these functions.

A more comprehensive, long-term solution to the power supply problems in the State is now needed. This need should not be rushed. There are substantial, complex issues associated with the future of the investor-owned utilities, the regulation of the electric power industry, and the provision of power to consumers. The department and others that will provide this role will require new direction for the long-term.

Some actions are needed soon to assure continuity and to prevent another abrupt transfer of responsibility for these functions. This may be no more than extending the department's authority until the long-term solution is established. Nevertheless, the department must continue to make substantial investments in its capabilities and substantial decisions on power purchases that should not be made without clear direction.

THE STATE CANNOT EASILY TRANSFER THE FUTURE MANAGEMENT OF EXISTING POWER CONTRACTS

The department's long-term agreements for power supplies do not provide the State with meaningful opportunities to renegotiate terms or to terminate the agreements. In addition, the department usually cannot reassign power contracts to utilities unless the sellers agree to the transactions.

Current Contracts Do Not Provide Meaningful Opportunities for the State to Renegotiate or Quit When Terms Become Unfavorable

The department's long-term power agreements do not give the department meaningful opportunities to quit or renegotiate if key provisions become unfavorable to the State. The most likely risks in this regard are that contract prices will exceed market prices for power and that contract quantities will exceed the department's needs.

Under the contracts, the department has the obligation to buy power. Hence, if the department quits performing (paying) temporarily or permanently without permission to do so under the contract, it will be in breach of the agreement and will be liable for whatever damages the contract or the courts provide for the breach. The department is always free to tell a seller that it will no longer pay for power delivered under a contract, but that declaration does not affect the seller's legal right to continue to deliver power, demand payment, and receive damages for the breach that covers the remaining life of the contract. Thus, the department's ability to stop paying is not the same as the right to terminate a contract.

Most of the department's long-term power purchase contracts allow the department to terminate a contract only in response to an event of default by the seller.

Most of the department's long-term power purchase contracts do not permit the department to terminate without cause. Instead, these contracts allow the department to terminate a contract only in response to an event of default by the seller. Although certain

provisions permit a termination payment that is akin to a buyout of the contract, it is up to the seller to choose between demanding that the department make the termination payment or demanding that until the agreement reaches its end date, the department continue to pay for the power for which it contracted.

The long-term contracts for power purchases also offer the department little in the way of excuses for temporarily not performing. The main excuse for failure to perform is "force majeure," which could, for example, involve an earthquake or other natural disaster beyond the department's control. However, the contracts expressly define this excuse for nonperformance to exclude adverse deviations in price, which result in the department's suffering a loss when selling power, as well as reductions in the demand for power, which result in the department having more power than it needs.

The Contracts Do Not Provide Meaningful Opportunities to Renegotiate if Contract Prices or Quantities Become Too High

Any renegotiating leverage that the department has is dependent on the rights that it has against the seller. For example, if the department has the right to demand some burdensome performance from a seller, then it has leverage to force a renegotiation. Other types of leverage to seek renegotiation can arise outside the contract from other business relationships between the department and the seller or from other legal relationships between them.

The department cannot walk away from the contracts without incurring penalties in the contracts, as well as potentially jeopardizing the department's and the State's position as a creditworthy contracting entity.

The only potentially meaningful contractual right that the department has that might serve as a basis for renegotiation is the right contained in many of the contracts to limit the department's liability for breach to the assets in the Department of Water Resources Electric Power Fund (electric power fund). To the extent that a seller fears that the electric power fund will not adequately compensate the seller for breach by the department, the seller might be willing to restructure the department's obligations under the contract. The seller can do so in much the way that a lender might renegotiate a delinquent note if the lender fears that the debtor's current assets would not adequately compensate the lender if it sued to enforce payment on the note. However, this leverage may be minimal because the department typically is required to establish and petition for a revenue requirement sufficient to fund its ongoing obligations under the power-purchasing program. Also, the department cannot walk

away from the contracts without incurring penalties in the contracts as well as potentially jeopardizing the department's and the State's position as a creditworthy contracting entity.

Similarly, the department's other types of leverage to force sellers to renegotiate are minimal. The most significant of these methods involve the department's rights to influence governmental action at state and federal levels that could provide the department with relief from unfavorable contracts. For example, the department has a statutory right to petition the Federal Energy Regulatory Commission (FERC) to void its power-purchase contracts to the extent that the rates are not "just and reasonable." In several of the long-term contracts, however, the department expressly waives this right or warrants that it will not petition FERC for such relief. Similarly, the State's ability to impose a windfall profits tax or similar tax on sellers when prices are excessively high or when supply does not meet demand has few practical effects since the long-term contracts typically provide that the department will be liable to the sellers for any increased costs imposed by such taxes.

The department's other types of leverage to force sellers to renegotiate the contracts are minimal.

Finally, a party's right to resist enforcement of its contractual obligations through litigation is sometimes sufficient leverage to force renegotiation. Typically, the long-term power-purchase contracts preserve the department's right to engage in full-blown litigation (as opposed to requiring alternative dispute resolution), although the Allegheny agreement requires arbitration for specific types of disputes. The Allegheny agreement is equally notable for its provision that if the department engages in an action that results in a provision of the contract being declared unenforceable or that reduces the contract price or amounts payable under the contract, Allegheny can declare a default and demand the termination payment. The extent to which the right to litigate provides leverage to force renegotiation depends on the seller's expectations regarding how protracted the litigation will be and on the seller's prospect of success. We do not consider the right to litigate in and of itself to be a source of substantial renegotiating leverage for the department.

The Department Can Assign the Contracts to Other Governmental Entities, but Assignment to Utilities Generally Requires the Seller's Consent

As of January 1, 2003, the department will lose the authority to enter new power-purchasing agreements as well as to pay salaries in excess of civil service salaries associated with the power-purchasing program. After January 1, 2003, the department

remains authorized to continue to administer existing contracts. The extent to which the department must continue to administer existing contracts, instead of turning them over to some other government agency or to an investor-owned utility, depends on the department's ability to assign its rights to a third party as well as on its ability to delegate its duties, or its contractual obligations.

The contracts permit assignment by the department or the sellers with the written consent of the nonassigning parties. The contracts also provide circumstances under which the department may assign the contracts without the sellers' consent. These circumstances, and the parties to which the department may assign its rights, vary among the contracts. Most of the contracts allow assignment to another governmental entity that can perform the duties of the department under the contracts without the sellers' consent. However, the assignment clauses do not provide the department with the flexibility to assign the contracts to other third parties, such as private utilities, without the sellers' consent.

For example, the department may assign its contracts with Calpine to another governmental entity if the department can demonstrate to Calpine's reasonable satisfaction that the assignment will not adversely affect the likelihood of receiving payments under the contracts. The department may also assign the contracts to a private utility if (1) the assignee's long-term debt is well rated, (2) the assignment is made as part of a transfer of all or substantially all of the department's power-purchasing agreements, and (3) Calpine is satisfied that the assignment will not adversely affect the buyer's ability to perform its obligations under the contract. The primary difference in the assignment to governmental versus private entities is that in the former, Calpine must have a reasonable objection to the assignment, whereas in the latter type of assignment, Calpine has the discretion to object for any reason, whether justifiable or not. Thus, Calpine effectively could prevent the department from assigning the Calpine contracts to a private utility.

Calpine effectively could prevent the department from assigning the Calpine contracts to a private utility.

The contracts with Coral are somewhat less rigid but similarly limit the department's assignment rights. The department may assign the contract to a creditworthy "California power authority or similar entity" without Coral's consent. However, the language does not give the department the clear right to assign to a private utility without Coral's consent. The Williams, Cal Peak, Sunrise, and El Paso contracts include similar assignment rights to a governmental entity, but these contracts contain no provisions for the department to assign its rights to a private entity.

Other contracts contain better (that is, more flexible) assignment rights for the department. For example, the department may assign the Allegheny contracts to another governmental entity or to a creditworthy electrical corporation without Allegheny's consent. Similarly, the Dynegy and Sempra contracts permit assignment to a governmental entity with powers, liabilities, and obligations similar to those of the department or without Dynegy's consent to a creditworthy electrical corporation.

In addition to barriers in the contract language itself, some contract terms may be practical impediments to the department's ability to assign the contracts to a nongovernmental third party. For example, the contracts all require payments out of the electric power fund, the department's liability is limited to the electric power fund, and the department is required to seek revenue requirements sufficient to infuse enough money into the electric power fund to cover all of its obligations. It is unclear how, or whether, a private utility could accept assignment of the contracts without fairly significant modification of the contract terms, and these changes would require the consent of the seller.

KEY ISSUES MUST BE RESOLVED CONCURRENTLY WITH THE DEVELOPMENT OF THE STRATEGIC PLAN

Key issues, which are not entirely within the Legislature's control, complicate the strategic plan's development, and they must be resolved concurrently if the plan is to be successful. For example, the ultimate resolution of whether Southern California Edison and Pacific Gas & Electric (PG&E) are creditworthy will have a substantial bearing on the department's exit options and its responsibilities in the future. As we discuss earlier in this chapter, some contracts allow the department to assign its rights to an electric company as long as the generator believes that the electric company meets certain credit requirements. Also, the future of the power-purchasing program will be affected by the roles and responsibilities established in the California Power and Conservation Financing Authority (power authority). For example, as we discuss in an earlier chapter, the department was concerned that the power authority was arranging to purchase power that does not complement the power-purchasing program's present portfolio.

The future of the power-purchasing program will be affected by the roles and responsibilities established for the power authority.

THE ENTITY ADMINISTERING THE POWER-PURCHASING PROGRAM MUST HAVE THE ABILITY TO CARRY OUT THE FULL FUNCTIONS OF A POWER-PURCHASING PROGRAM OF THIS SCALE

It is unclear whether any or all of the functions for the power-purchasing program should stay within the department.

The entity that administers California's power-purchasing program must operate in an environment in which it is competing with private businesses that have various advantages over the department. These business have fewer constraints than does the department, more experience with the scale involved, and more extensive experience managing risk related to the size and types of transactions. These risks include various market risks, credit risks, legal risks, and regulatory risks. Thus, it is unclear whether any or all of the functions for the power-purchasing program should stay within the department.

Currently, the department does not have the same authority as its competitors do to use financial contracts to adjust some of its market risk, particularly in the area of natural gas. Also, even with the broad authority contained in AB 1X, the department has been unable to hire staff at the pay levels it believes are necessary to compete in the marketplace. If the program does stay within the department, significant consideration should be given to contracting for entire functions that the department is unlikely to be able to perform effectively itself. For example, although the department may find that it can perform the short-term trading function effectively, given the anticipated volume, it may find that the function of managing the legal aspects of the complex contracts is beyond its capacity.

Regulatory risks also need to be managed. The department's power-purchasing program is directly affected by actions taken in regulatory proceedings. Although neither the California Public Utilities Commission (CPUC) nor FERC has regulated the department directly, the actions of those commissions have substantial bearing on the market within which the department operates, the load and services for which the department is responsible, and the collection of revenue. These agencies also oversee the actions of the players with which the department contracts to conduct the program—suppliers, investor-owned utilities, and the California Independent System Operator (ISO). In addition, FERC actions increasingly raise questions about the role of that agency in the oversight of the department's conduct of the power-purchasing program.

Also, it is unclear whether these functions should stay within the department. While the placement within the department was logical during the crisis, it may not be so for the long term. For example, if management of the net short reverts back to the investor-owned utilities, the primary function remaining is that of managing the complex long-term contracts—not a function with which the department has had extensive experience.

The establishment of a nongovernmental entity to assume these functions would be problematic due to the previously discussed assignment rights in the contracts that generally allow assignment to another governmental entity. However, transferring the responsibility to an entity that is similar in nature to the ISO could be explored. The ISO is a governmental entity in some respects, but it lies outside the constraints of the civil service hiring process.

THE DEPARTMENT'S RESPONSIBILITIES REMAIN SUBSTANTIAL

One of the most daunting responsibilities for the department will be its legal management of the long-term contracts under which it will spend on average approximately $4 billion per year.

The department's ongoing responsibilities are substantial and should not be underestimated. It remains the only creditworthy buyer in the market and must continue to manage the net short through 2002. Because managing the net short requires the department to enter contracts, and because the department's statutory ability to enter power agreements ends on December 31, 2002, the department has no statutory authority under AB 1X to continue managing the net short beyond 2002. Also, the department must continue to invest staff resources to secure the sale of bonds to reimburse the State's General Fund for the power purchases that occurred early in 2001. As we discuss in earlier chapters, the department must carefully manage its portfolio since it is exposed to market risk in high-peak demand periods if supply shortages occur. Also, the net-short analysis will become increasingly complex as dispatchable contracts take effect. However, one of the most daunting responsibilities for the department will be its legal management of the long-term contracts under which it will spend on the average of approximately $4 billion per year.

Contract Management Is Necessary to Help Limit the Remaining Costs and Legal Risks

Although the department has created a Contract Management Protocol with the assistance of its consultant, that program focuses largely on business, not legal, issues. In fact, according to its

consultant, the protocol's role is to provide everything but legal contract management. In its August 27, 2001, *Contract Management Report and Protocol*, the department instituted:

> " . . . a deep dive analysis . . . a detailed assessment of each contract to ascertain those "key elements" which will form the focus of contract management. These thorough examinations of each contract will be directed on a priority basis by the "Contract Manager" with consultation from Planning and Strategy, the Fuel Group, Risk Management and Operation Monitoring to determine which issues warrant review, monitoring and evaluation."

Note that although the "deep-dive" analysis is performed by the contract managers with consultation from a variety of points of view, the analysis lacks any legal review.

Our review of those same contracts on which the department's staff did "deep dives" in September reveals that their analysis failed to identify some of the terms and conditions of the contract language that could raise significant legal issues (or opportunities) in the future. For example, the team's "deep dive" of the Williams contracts failed to note a very troublesome event of default in the contract that exposes the department to significant liability. Under the contract, "any action or inaction by any governmental entity which has an adverse impact or otherwise limits or alters adversely" the economic benefit and burdens conferred on Williams constitutes an event of default by the department.

A whole variety of conduct by the State and local government—whether licensing, permitting, taxes, or other regulation—could adversely affect the economic benefits of the contract to Williams and constitute an event of default.

Under this overly broad language, a whole variety of conduct by the State and local government—whether licensing, permitting, taxes, or other regulation—could adversely affect the economic benefits of the contract to Williams and constitute an event of default. For example, a large rise in the property tax on generators could increase Williams's operating costs and reduce its profits. Note that this provision is not simply a "pass-through" whereby the department reimburses Williams for its increased cost of service and the contract continues. This provision is much more serious: It is an event of default, under which Williams may terminate the contract. With an event of default, Williams and the department do not simply walk away from the contract; Williams has the right to collect early termination payments of more than $400 million from the State. Clearly this provision of

the Williams contract is a serious liability that "warrants review, monitoring and evaluation" by the department, but it was not identified by the "deep dive" recently performed by the department.

The analysis of one contract determined that the department must pay air emissions costs the generator incurs while producing power for the department. This exposes the department to $400 million to $688 million in potential emissions costs over the life of the contract.

The "deep dive" analysis of selected contracts did in some instances identify trouble spots in contract terms but failed to recognize the long-term implications of the problem. For example, the analysis of the Williams contract did identify a provision stating that if Williams incurs air emissions costs as a result of producing power for the department, those costs must be paid by the department. However, the analysis was limited to whether the Williams invoices had in the past included charges for air emissions credits. Apparently because no emissions credits were charged to the department for the summer of 2001, the recommendations section of the analysis says nothing more about the pass-through. This omission means that the department has overlooked a potentially large and volatile cost: The average price for air emissions credits in 1991 was $4,284 per ton; during the first months of 2000 it increased tenfold to $45,000 per ton. For a plant like Williams, the omission in the contracts exposes the department to pass-through costs in potential emissions credits of $400 million to $688 million over the life of the contracts.

Although no air emissions credits were passed to the department in 2001, a significant unanswered question remains as to whether those costs will be passed to the department for the remaining 8-plus years of the contract. For example, the department needs to explore the effect of the February 8, 2001, executive order that eased regulations concerning air emissions credits for the summer of 2001. Under that order, the governor required the local air pollution control and air quality management districts to modify emissions limits that restrict the hours of operation in air quality permits as necessary to ensure that power generation facilities that provide power under contract to the department do not have constraints in their ability to operate. Because the executive order suspending emissions charges expires on December 31, 2001, the department needs to know whether the State will waive air emissions credits for the department's projects for the next 9 years and, if not, what steps it needs to take to minimize emissions charges incurred from the operation of the Williams generation. For example, it could do the following:

- Reduce the amount of power it buys from Williams when emissions credits are the most expensive.

- Work with Williams to improve the environmental quality of the plant.

- Explore appropriate solutions with the appropriate air district.

However, unless the issue is properly identified, the department cannot take any steps to minimize the exposure and instead will not see the issue until it is too late—that is, until the emissions credits appear on the invoice for summer 2002.

While we do have concerns about the "deep dive" analysis, we should note that it is quite hard for someone who has been involved in the negotiation and drafting of a contract to separate the words on the written page from his or her overall understanding of the deal made by the parties. The reviewer brings to the review preconceived notions of how the contract is "supposed" to operate, making it difficult for the individual to spotlight either defects or opportunities. Further, it is difficult for someone who is not a lawyer to appreciate the significance and potential ambiguities of the terms and conditions of contracts. Due to the nature of their work, lawyers are alert to the things that can go wrong with a contract, while business people are focused on making the deal go right. Finally, lawyers are often attuned to legal risks outside the contract. These risks arise not only from the operation of the contract language but from the interplay between the contract obligations and the State's obligations outside the contract. Lawyers are trained to look at a client's problem or question not in isolation but in the context of the entire web of the client's legal relations. For example, air quality is regulated at the federal level as well as at the state level, and permitting generators to exceed previously established emissions levels may affect California's legal relationships with the federal government.

It is very hard for someone who has been involved in the negotiation and drafting of a contract to separate the words on the written page from his or her overall understanding of the deal made by the parties.

Thus, we recommend that the department retain a "fresh set of eyes"—legal eyes—to do a fine-tooth-comb analysis of the contracts. Until it has a more thorough identification of the important legal issues, the department will not be ready to move on to the other steps of legal contract management, including prioritizing the issues, strategizing solutions, and committing resources to move ahead. Admittedly, this identification will be a time-consuming and expensive task, but given the magnitude of the liabilities that the department faces—hundreds of millions of dollars if a default is declared on just one of the larger contracts—the investment is justified.

Review of Legal Contracts Typically Involves Identifying "Swords" and "Shields"

The starting point for any analysis of a legal contract is identification of issues. This process must occur before one can develop strategies to prioritize and manage those issues. The review team for the department should seek to identify the following two types of issues:

- **The shields.** What are the contracts' trouble spots that the department needs to guard against? Where are the department's liabilities and points of weakness? The goal is to identify clauses in each contract that may increase the department's financial exposure or cost of power, to develop a strategy to monitor the potential event, and, if possible, to take steps to prevent the event.

- **The swords.** What are the department's leverage points in the contracts? What are the department's opportunities and points of strength? The goal is to identify leverage points and ambiguities to try to gain better performance from the generator, reduce the cost of power, or extract contract concessions. In this way, the department can plan and act proactively to maximize the value of its contracts.

The Department Needs to Shield Itself Against Potential Events of Default

Events of default present a major financial exposure for the department.

An example of the need to identify shields involves the contract provisions for declaring an event of default, which present a major financial exposure for the department. Generally, declaring an event of default is optional for the seller. If the contract continues to be advantageous to the generator, it probably will not exercise its right to declare an event of default. That situation does not mean, however, that the event of default is not a problem in the contract; instead, the potential event is simply a time bomb that has not blown up, yet. If the contract becomes disadvantageous to the generator, it will aggressively pursue these events of default as an excuse to get out of the contract and collect damages.

Because the average market price has been lower than the average contract price since some of the power has started to be delivered under the contracts, no generator may currently be seeking to terminate its contract. However, should the market shift, the importance of events of default also shifts. The department should not be lulled into believing that the events of default in

the contracts are not problematic based on the experience of summer 2001. Indeed, if market prices during the past summer had been significantly above contract prices and if electricity had been in short supply, sellers might well have exercised their rights of termination for the department's failure to issue bonds, albeit without termination payments.

In addition to the specific events of default set out in the contracts, these agreements also provide more generally that the breach of a material covenant constitutes an event of default. Thus, the covenants made by the department in the contracts should be considered events of default unless the terms provide otherwise. Events of default can include breaches of any standard covenants providing that payments under the contracts will be treated as an operating expense of the electric power fund and that the department's power, rights, and duties (for example, to apply for a revenue requirement) will not be impaired.

After identifying its exposure to events of default, the department can prioritize the size of the exposure and consider how it may be able to manage the risk. Different risks present very different problems and require different strategies. For example, in the Williams contract, the default based on government impairment of the value of the contract poses hundreds of millions of dollars of exposure for the department; however, most of the triggering events are outside the department's control. If a local government imposes oppressive new operating limits on the Williams generators, the department's power to control that event may be limited. In this case, the department's strategy needs to be attempting to reform the terms of the contract itself, whether voluntarily through renegotiation or forcibly through litigation. Alternatively, the department may decide that the likelihood that Williams will want to use that event of default to trigger termination is remote because the contract is so financially beneficial to Williams, and therefore the department may not dedicate any of its resources to the problem.

In the Williams contract, the default based on government impairment of the value of the contract poses hundreds of millions of dollars of exposure for the department; however, most of the triggering events are outside of the department's control.

Another example of an exposure to default is the covenant relating to the bonds, which requires that the generators' invoices be paid as operating expenses under the bond before the General Fund is repaid for the more than $6 billion that the State paid for energy. This event of default is within the State's control. If, however, the State were to repay the General Fund from the bond proceeds before the generators receive payment, the State's action could be an event of default resulting in termination of most of the contracts and exposing the State to huge early termination

payments, depending on the market at the time. The department's strategy with this bond covenant may be to work with the Legislature to communicate the effect that changing the bond structure would have on the cost of terminating the contracts.

The Department Also Needs to Shield Itself Against Generator Costs That Have Become Its Responsibility

Another example of the need for a shield involves the pass-through of certain costs to the department. As we discuss earlier, although the generator generally bears the costs of operating a plant and producing power, some of the contracts shift to the State these generator costs of doing business. Legitimate reasons may underlie this shift; however, it is critical to identify these clauses so that the department can monitor and manage the potential increases in the cost of power. Some of the pass-throughs that need to be identified, analyzed, and managed include the following:

- Governmental charges, including taxes at state and local levels.
- Costs related to environmental compliance, such as:
  - Emission offsets.
  - Emissions penalties and fines.
  - Lost revenues in the event that the supplier is unable to sell to other buyers because the supplier has used up its emissions credits in generating power for the department.
- Scheduling imbalance penalties (for example, from the ISO).
- Gas imbalance charges.

After identifying the various pass-through costs, the department must evaluate those that present the greatest exposure for the department and can be remedied or reduced by department action.

After identifying the various pass-throughs, the department must evaluate those that present the greatest exposure for the department and can be remedied or reduced by department action. The department can use various strategies to minimize the effects of pass-throughs. For example, the department can identify ways to improve its own scheduling of a generator with a pass-through in its contract to avoid imbalance charges. The department can also monitor proposed legislation and if, for example, a windfall profits tax on generators is proposed, inform the Legislature that such a tax would increase by a certain amount the cost of power that the department must purchase given the number and size of contracts with pass-throughs of governmental charges. Also, the

department can monitor and communicate with the local air emissions districts in which the plants with emission pass-throughs are located. It might determine that the emissions charges could best be controlled by paying for a capital improvement at a generating facility to reduce the need for air emissions credits. Knowing how many contracts contain particular pass-throughs can influence whether the department intends to take an aggressive read of the terms and perhaps pursue litigation of the clauses since more than one generator may be affected.

The Department Needs to Identify Swords That It Can Use to Negotiate Better Contract Terms

The department needs to identify the disadvantageous terms of contracts and then use its strengths in the contracts to leverage a change in those terms.

The key to the sword analysis described earlier is to identify the disadvantageous terms of contracts and then to use the department's strengths in the contracts to leverage a change in those terms. The first step is to identify entire contracts that are disadvantageous and then to prioritize the value of the various contracts. For example, looking at the 20 largest contracts, the department should determine which are the most beneficial to the State and which are the least beneficial. The department can base its priorities on a number of factors, including the following:

- The department's need for the contract's power in the portfolio, whether in specific years, type of product, or delivery point.
- The price of the power as compared to prices in other contracts.
- The generator's history of reliability and availability.
- Potential liability exposure to the department (lurking events of default).

The department needs to target for detailed scrutiny the contracts that are the least desirable and that have the most dollar impact to determine their weaknesses. Similarly, the department should target the most disadvantageous contract terms, and contracts that contain those terms that need scrutiny to determine what leverage points can be developed to remove or at least to modify the disadvantageous terms.

It is important to recognize that the points of leverage in a contract are not necessarily the same as the disadvantageous terms; in fact, they are generally different. For example, one of the disadvantageous terms in the Calpine contracts is that the pass-through of governmental charges includes new taxes and

charges imposed by the federal, state, and local governments. If the department decides that its goal is to narrow that pass-through to statewide taxes only, it may identify a completely different clause of the contract to use to obtain leverage.

For example, if Calpine wants to assign its contract and needs the department's consent, the department can try to barter its consent to an assignment in exchange for a narrowing of the language in the contract's governmental charges pass-through. Similarly, if a generator cannot meet a milestone, the department may agree to delay the milestone date if the contract terms relating to dispatch are amended. The department can also aggressively pursue its rights to do capability audits and, if a generator fails, choose to waive any penalty in return for the deletion of a disadvantageous contract term.

Opportunities for leverage can include, for example, the following elements:

- Terms that establish performance minimums for the generator.
- Terms that permit the department to monitor performance, such as capacity tests or performance audits.
- Deadlines, such as commercial operation dates or other milestones, that the generator may wish to modify.
- Items that require the department's consent, such as consent to assignment.

Recent Action Taken by the Board of Equalization Highlights the Need for Active Contract Management

A recent amendment would permit a state assessment of all generating facilities with a capacity of 50 megawatts or more that are owned by electrical corporations, opening the way for higher taxation on generators.

A recent action by the California Board of Equalization (board) highlights the need for the department to manage its power-purchasing agreements in anticipation of future trends and legal changes. On October 24, 2001, the board amended Rule 905, Assessment of Electric Generation Facilities, in a way that opens the door to significant increases in property taxes on generators. Under the current law, generation facilities are generally taxed locally, and thus increases are limited to 2 percent. The amendment would permit a state assessment of all generating facilities with a capacity of 50 megawatts or more that are owned by electrical corporations, opening the way for much higher taxation on generators. According to a board spokesperson, the purpose of the amendment is to increase property taxes paid by generating

facilities. Specifically, the spokesperson was quoted in the media as saying, "The [board] felt that these generators were making enormous profits and consumers weren't seeing any of the benefits of deregulation . . . Right now, power plants are protected under Proposition 13, meaning they don't pay taxes based on fair market value."

Many of the generators who entered into the largest contracts with the department contemplated exactly the risk that taxes aimed at generators could adversely affect their contracts and insisted on contract terms that would shift this risk to the department. These "governmental action" provisions require the department to absorb either tax increases directed at generation of electricity or all tax increases, even those applying generally. In other words, many generators to whom the amendment is directed have the contractual right to pass through the tax increase, dollar for dollar, to the department. Thus, at least some of the real effect of the proposed increase will be absorbed by the department and then by California ratepayers.

It is clear that when adopting the amendment that may increase property taxes on generators, the board had no idea of the potential costs to the State under the power-purchase contracts.

It is clear that when adopting the amendment, the board had no idea of the potential cost to the State under the power-purchasing contracts. In its Initial Statement of Reasons Summary, the board determined that "the proposed amendments will result in no direct or indirect cost or savings to any other State agency."

More than 15 large, long-term contracts have clauses allowing the pass-through of governmental charges that would pass any such property tax increase directly to the department. There is no evidence, however, that the department has identified which contracts have these clauses or that it has tried to evaluate the exposure. Further, the event of default provisions in the Williams contract could be construed to mean that such property tax increases constitute a default with termination payments. However, as we noted earlier, the "deep dive" did not identify the issue. There is no evidence that the department has informed the board about the potential adverse effect of the amendment on the State or even that the department was aware of the problem.

This example demonstrates the need for the department to do several things: Identify the problems in the contracts that need shields. After identifying such issues, the department needs to prepare for the outcome of those issues. Given the scope of provisions such as the "new tax" and emissions pass-throughs, the department may wish to monitor legislative and agency actions that could have an impact on the sellers' costs and might

thus give rise to that cost being passed through to the department and ultimately to California ratepayers. The department may also wish to give notice of the contract terms to California agencies (such as the board) so that they become aware of the contractual effects of actions that they take to increase taxes (or other charges) paid by the sellers.

The Program Would Benefit From Renegotiated Contract Terms as Well as a Renegotiated Contract Price

Although the department's ability to compel energy producers to renegotiate the contracts is limited, some producers may be willing to do so. If any are willing, the department should not limit its interest in renegotiating the contracts to just the base price of the delivered power. For example, the department would benefit significantly if it could renegotiate out of the contracts, the terms that make the contracts expensive and difficult to manage. These terms increase the remaining cost risk due to price escalators that could significantly increase the price above the base price. In addition, the department would benefit if it could renegotiate into the early contracts the reliability terms that some of the same generators agreed to in later contracts. Also, the department may be able to lessen future costs of selling excess power from high-priced contracts into a low-priced spot market if it could renegotiate the amount of nondispatchable power south of the Path 15 transmission congestion point during 2003 and 2004 so that some of the projected excess could be delivered after the transmission congestion is resolved. Renegotiating a lower base price is a valid objective now that the energy markets have stabilized and the perceived credit risk has been lessened. However, the department should not focus exclusively on this one aspect of renegotiating the contracts to the exclusion of mitigating the type of problems with the contract terms that we identify in our report.

THE DEPARTMENT NEEDS TO IMPROVE ITS CAPABILITIES AND ITS SHORT-TERM PURCHASE OPERATIONS

The net-short analysis will become increasingly complex as the department's dispatchable long-term contracts take effect.

As we discuss in an earlier chapter, the department needs to improve its capabilities and revise its short-term purchase operations. Although the department was prompt in assessing its new business requirements, it has had serious difficulties staffing the power-purchasing program. The department remains heavily dependent on consultants and outside expertise. It also needs to improve its analysis of short-term energy purchases so that it will

have a more fully informed understanding of its energy needs and its cost exposure and will be able to optimize its purchasing strategy for short-term agreements. In addition, the net-short analysis will become increasingly complex as the department's dispatchable long-term contracts take effect. Furthermore, the department's short-term transactions are not effectively coordinated with utility-owned generation.

With or without efforts to renegotiate the price or terms of the contracts, the contract management tasks will be formidable.

Also, as we discussed earlier, the department has a significant effort ahead of it related to the legal management of the contracts. With or without efforts to renegotiate the price or terms of these contracts, the contract management tasks will be formidable and will require the expertise of individuals with prior experience performing the task. If the costs of the pass-through provisions discussed earlier are not adequately monitored, the price of the energy purchased could significantly increase above the base amount in the contracts.

The Department Needs to Improve Its Servicing Agreements With Investor-Owned Utilities and the Procedures to Monitor the Agreements

Although the department has completed the necessary agreements to cover a substantial part of its activities with the investor-owned utilities, some elements of the agreements need improvement. The agreements make the department responsible for the cost of excess purchases resulting from differences between investor-owned utility estimates of customer usage and actual customer usage, but the utilities have no obligation to minimize such deviation. The department and the investor-owned utilities also have not yet reached agreement on sharing the market data needed to agree on the costs of power purchases needed to fill the demand for electricity on an hour-by-hour basis and to balance the electricity in the power grid with the total demand (real-time purchases). Nor have they reached agreement on sharing the costs for needed electric power reserves and ISO operating costs. In addition, the department lacks processes to monitor the investor-owned utilities' performance under the agreements. As a result, the department may unnecessarily be at risk for the cost of overscheduling power for delivery and cannot be certain that it receives all of the revenues that are due from the investor-owned utilities.

Under the agreements with the investor-owned utilities, the department will purchase and schedule power based on customer usage estimates provided by the utilities. However, under the

power-purchasing program, customers are charged only for the power delivered to them based on their actual usage, and the department must sell any surplus resulting from differences between estimated and actual customer usage and must suffer any losses resulting from those surplus sales. The servicing agreements state that in the event of persistent deviation between estimated and actual customer usage, the investor-owned utilities will review their forecast methodology and report to the department, but they have no obligation to correct or minimize such deviation. Only the agreement with PG&E contains additional language regarding deviations between estimated and actual customer usage. That agreement states that in the event of persistent deviations of an identified magnitude, PG&E and the department will meet, confer, and cooperate in an attempt to modify any scheduling practices that produce the deviations.

The revenue remittance provisions of the servicing agreements cover only power purchases that are prescheduled in the day-ahead or hour-ahead markets based on customer usage estimates provided by the investor-owned utilities. Real-time power purchases are not covered by these agreements. The department is currently negotiating with two of the three investor-owned utilities to reach agreements, known as imbalance agreements, on who will pay for real-time purchases and the related costs, for reserve electric power capacity, and for ISO operating costs. Additional issues to be negotiated under the imbalance agreements include the order in which the ISO will dispatch energy generated by the investor-owned utilities and energy purchased by the department to customers, and whether, in times of excess energy, the department will sell power generated by the utilities or department-purchased energy. The department has already reached an agreement with the third investor-owned utility.

The agreements contain provisions that require specific performance by the investor-owned utilities; however, the department has not yet designed nor implemented a strategy to monitor their performance.

Further, the agreements contain provisions that require specific performance by the investor-owned utilities; however, the department has not yet designed or implemented a strategy to monitor their performance. According to the chief of the Risk Management and Fiscal Office, the servicing agreements were recently approved by the CPUC, and the department has not had time to assemble monitoring procedures. However, some of the activities covered in the agreements, such as revenue remittances, were ongoing before the CPUC's approval of the servicing agreements.

The agreements describe how the investor-owned utilities will calculate and remit receipts for power purchased on their behalf by the department and collected from the utilities' customers. These agreements include specific procedures that the utilities are to follow in calculating receipts for power purchased by the department. These procedures include making adjustments for uncollected bills, adjusting estimated receipts for actual receipts, reducing remittances for the costs of energy conservation and energy demand management programs, and establishing a priority for posting customer payments for electrical power and natural gas purchased by the department and by entities other than the department.

As of September 30, 2001, the investor-owned utilities had remitted approximately $2.3 billion to the department that they had collected from their retail customers for power purchased by the department, and they had reported approximately $225 million for the costs of energy conservation programs. However, the department currently has no methods to ensure that it receives all of the revenue to which it is entitled from the sale of electric power, nor does it have any means to ensure that the investor-owned utilities promptly remit revenues. One of the department's consultants is currently developing a system that will allocate the department's power purchases to the investor-owned utilities and provide the associated data the department will need to bill for the purchases and track the associated balances. The department's consultant anticipates that it may complete the system by December 2001.

The servicing agreements also provide audit rights to the department and reporting responsibilities to the investor-owned utilities, but the department has not yet developed and implemented procedures or requirements for these.

The servicing agreements also provide audit rights to the department and reporting responsibilities to the investor-owned utilities, but the department has not yet developed and implemented procedures or requirements for these. One powerful tool available to the department in monitoring the performance of the investor-owned utilities gives the department an opportunity to gain independent verification of compliance with critical elements of the agreements. The annual report provision requires that the investor-owned utilities provide the department a report prepared at least annually by independent auditors on the utilities' compliance with their obligations under the agreements. The report is to include the procedures performed (the scope of which is to be agreed upon with the department), the results of the procedures, and any exceptions noted. In this way, the department can gain assurance that the investor-owned utilities comply with critical elements of the servicing agreements, such as revenue remittance, in an administratively feasible manner.

The Department Needs Continued Improvement in Its Efforts to Prevent Conflicts of Interest Among Its Consultants

Although the department has taken steps to prevent conflicts of interest among its consultants and has implemented a policy that requires them to file the State's standard form for disclosure of economic interests, its process has not accounted for all consultants working on its many projects. Conflicts of interest can arise when employees or consultants have financial interests that may compete with their duties in service of the State and that could result in an economic disadvantage to the State. In response to assertions that it did not ensure that its advisers and consultants disclosed any economic interests that may conflict with their tasks at the department, the department evaluated its consultants and employees against its conflict-of-interest code in July and August 2001. In addition, it designed a system to track those individuals it determined needed to file economic interest disclosure forms.

The department indicates it is currently conducting another review of its consultants to ensure that those required to file economic interests disclosure forms have done so.

However, the department's evaluation and tracking system records do not include all members of its consultants' staff. Comparing the department's file of contracts to its current tracking system, we identified 15 individuals for whom the department had no evidence of any effort to determine the need to file economic interests disclosure forms. In addition, we compared the August 2001 invoice from one of the department's large contractors to the tracking system and found that 22 of the 42 consultants, ranging from office services workers to directors, who worked on the department's projects that do not appear in the department's tracking system.

According to the chief of the administration unit, the department is currently conducting another review of its consultants to ensure that those required to file economic interests disclosure forms have done so. In addition, it has adopted a policy of reviewing all employees and consultants twice each year to demonstrate due diligence, and it will retain a record of its review for each review period.

When the department does not account for all of its consultants in a central record of its efforts to ensure proper disclosure, it loses some assurance that it has prevented possible conflicts of interest among its consultants. Moreover, because disclosure of economic interests is an annual requirement, if the department does not maintain a complete list of those consultants who are required to file disclosure statements, it cannot be certain that all consultants make the required annual filings.

Departmental Controls Do Not Ensure the Segregation of Costs for the Power-Purchasing Program

The department paid $1.1 million from the electric power fund for consultant services unrelated to AB 1X. The department subsequently corrected this error.

The department's controls were not adequate to ensure that all charges to the power-purchasing program related to the program. Also, when the department identified errors, it did not completely correct the errors. The department paid a consultant's invoices totaling $1.1 million from the electric power fund for services unrelated to AB 1X. The purpose of the consulting contract was to assist in the design and development of a recovery plan for the investor-owned utilities and any asset purchases related to the recovery plan, which is outside the scope of AB 1X. The department subsequently identified that $825,000 should be charged to a different funding source, but it did not correct the remaining $275,000 until we brought it to the department's attention.

The department also made payments from the California Water Resources Development Bond Fund (bond fund) for the power-purchasing program due to confusion in the first two weeks of the program on whether the purchases were for the power-purchasing program or for the State Water Project. In May 2001 the electric power fund reimbursed approximately $31 million erroneously charged to the bond fund. In July and November, errors in the opposite direction of approximately $8 million were corrected. However, the department has not corrected for any interest lost by the bond fund due to the erroneous charges that it corrected.

The department's controls were not adequate to ensure that staff charged to the power-purchasing program all payroll charges that should have been charged or that when the department corrected errors, it completely corrected the errors. Using a data file of expenditure information provided by the department, we identified approximately 14,300 hours for which department staff worked on the power-purchasing program and for which no payroll costs were charged to the program. The department provided us with a report in late November 2001 that identifies individuals with hours totaling 13,300 who have no payroll charges to the power-purchasing program. Regardless of the difference, the department has corrected only the charges for approximately 4,300 hours related to employees who do not have management positions. However, the department did not provide us with any information that demonstrated that it had ever made a correction for the management employees or that its adjustment was complete for the nonmanagement employees whose hours appear on its report showing the 13,300 hours.

RECOMMENDATIONS

Policy Recommendations

The power-purchasing program was conceived and has been conducted during an unprecedented crisis. The crisis has abated to a large degree, and the State and the department now need to reassess with a longer-term perspective the goals of this power-purchasing program and the program's implementation.

At this juncture, in view of the evolving creditworthiness of the investor-owned utilities and the emerging role of the power authority, the Legislature and the governor should consider the following actions:

- Develop a comprehensive, long-term strategic framework for the electricity industry in the State and for the department's role in that system.

- Establish an appropriate statutory framework, including the possible amendment of AB 1X, to extend the department's purchasing authority in order to allow adequate time to implement the strategic framework, to afford more flexibility in the termination of the department's purchasing authority, and to assure continuity of the purchasing function and an effective transition for this function, presumably to the investor-owned utilities.

In the context of the evolving state policy on the future of the industry and the power-purchasing program, the department should take these steps:

- Create a strategic plan for the future of the power-purchasing program at the department, including the assessment of the transition processes needed to allow orderly transfer of functions to the ISO, the investor-owned utilities, and others, as appropriate.

- Continue efforts to coordinate the responsibilities of the department with respect to the power authority to establish clearly the roles and responsibilities of each organization.

Recommendations for Portfolio Planning and Management

With the substantial long-term contract portfolio in hand, the department's portfolio planning and management focus now must shift to aggressive cost and risk management, coupled with thoughtful planning of any necessary additional purchases and sales. The department has recognized the need for this new focus and has begun planning for this new phase of its AB 1X responsibility. Actions taken or initiatives underway include these:

- **Energy Transacting and Risk Management (ETRM) System**—a database system designed as a decision support and management tool to support portfolio management, risk assessment, and pricing analysis for transactions and contracts. The system is scheduled for implementation in two phases during the first two quarters of 2002, and it is designed to address market risk, financial risks, and credit risk.

- **Contract Management Protocol**—an organizational structure and set of business processes being implemented in fall 2001 designed to conduct the contract management function related to the power-purchasing program.

These initiatives are clearly important, and the department should implement them as soon as possible. In doing so, the department should also take these steps:

- Conduct within 90 days, in conjunction with the legal review noted below, an in-depth economic assessment of the contracts and the overall supply portfolio serving the investor-owned utilities' customers to assure that the department can develop an effective overall contract management strategy. This assessment should focus on how the contracts fit into the overall portfolio and on the costs relative to current expectations of market conditions.

- Develop a contract renegotiation strategy, informed by the legal and economic reviews, that focuses on improving the reliability and overall performance of the portfolio.

- Assure that the contract management plan system addresses the department's obligations under the contracts both before and after the in-service dates.

- Consider staffing approaches, including further consultants and contractors if needed, to assure that personnel shortages do not continue to hinder the development and implementation of these systems.

- Establish a planning process that more directly integrates the entire portfolio of supplies serving customers of the investor-owned utilities with the role of the department's contracts in that portfolio. As specified in AB 1X, this process should include consultation with the CPUC and with the investor-owned utilities.

Legal Recommendations for Power Contracts

The department now holds many long-term power contracts, and it must administer and manage those contracts. Delivery of power has begun or will soon begin under many of these contracts. Delivery on other contracts awaits the completion of construction on new power plants. As noted in Chapter 2, these contracts have many "seller-friendly" provisions that represent important legal risks to the department. It is important to recognize that the sellers are, for the most part, large, sophisticated power organizations with substantial legal resources at their disposal. In short, the department now has a substantial legal challenge to assure that the State obtains maximum value from these contracts and that the department effectively manages legal risks. Further, it is reasonable to assume that with a long-term contract portfolio of this size and complexity, the department will have some litigation with the generators concerning the interpretation of the terms and conditions of the contracts. In this context, the department should do the following:

- Conduct in-depth assessments of legal risk and of legal services requirements within 90 days to assure that the department can develop an effective legal management strategy, including an effective "swords and shields" plan.

- Establish an ongoing legal services function that specializes in power contract management, negotiation, and litigation to assure that the department's legal assessment and representation is on par with those of the other parties participating in the contracts. When necessary to avoid conflicts, this legal function should be separate and distinct from counsel retained to sell bonds or to provide legal advice to the State Water Project.

- Investigate all audit and other rights available to the department under its contracts to assure that it can develop a proper performance enforcement program.

Recommendations for Short-Term Transactions

The department's short-term transactions functions must also shift to reflect the changes brought with the long-term contracts. While the overall volumes of short-term and spot purchases will decline, the need for active scheduling and trading, settlements, coordination with the ISO and with investor-owned utilities, and management of the net short remains. The power-purchasing aspects of this function will end at the close of 2002; however, other functions will continue in some capacity as part of the management of the long-term contracts.

Department actions taken or initiatives underway to improve these functions include the following:

- **Power Scheduling and Settlements System**—a system designed to support the power scheduling and ISO settlement functions. Scheduled for implementation in the fourth quarter of 2001.

- **ETRM System**—this system provides support for short-term trading and management as well as for the longer-term portfolio management discussed above.

These actions are obviously important, and the department should implement them as soon as possible. In doing so, the department should take these actions:

- Clarify and resolve settlement process problems associated with the energy and ancillary services functions that the department has been and continues to conduct on behalf of the ISO.

- Conduct an assessment of the imbalance energy sales and purchases volumes to determine whether they are significantly increasing the department's net power costs. If so, the department should develop plans to mitigate those costs.

- Enhance the organization's skills for market analysis and contract management to properly address the implications of uncertainty on portfolio management and dispatch decisions.

- Fully staff the power-purchasing program. Although the program's organization has come a long way, it lacks adequate staff to match the magnitude of its trading and related activities (for example, planning, settlement, and fuel management). The planning and operational duties will also increase in the coming months as a significant amount of dispatchable long-term contracts take effect.

- Develop a transition plan for the orderly transfer of the short-term purchasing and net short management functions at the conclusion of the AB 1X purchasing authority.

- Consider staffing approaches, including further consultants and contractors if needed, to assure that personnel shortages do not continue to hinder these operations over the next year and to provide for an effective transfer of the purchasing functions at the conclusion of the AB 1X authority.

At present, the transaction activities are not effectively coordinated with the utility-retained generation. Due to the lack of coordination, the combined investor-owned utilities and department resources are not being used to minimize the total costs of serving the customers of the investor-owned utilities. Potential savings from coordinated operation could be in the tens of millions of dollars per year. A coordinated dispatch is achievable, and it should be achieved soon. Therefore, the department needs to do the following:

- Collaborate with the investor-owned utilities to share information about their respective generation sources and to organize a least-cost dispatch of those sources. The investor-owned utilities also need to commit to this effort and to plan for ongoing coordination when the investor-owned utilities reassume the net-short purchasing authority, including coordination of dispatch with the department contracts.

- Coordinate with the investor-owned utilities to ensure that the collective supply sources operate in a manner that minimizes the total cost of providing energy and ancillary services.

- Work with the investor-owned utilities and the CPUC to ensure that the rate incentives associated with utility-retained generation scheduling are resolved to support a least-cost dispatch.

OTHER RECOMMENDATIONS FOR IMPROVING THE POWER-PURCHASING PROGRAM

To improve its ability to carry out the full functions of a power-purchasing program of this scale, the department should take these actions:

- In its future efforts to protect the interests of the power-purchasing program, the department should retain independent legal counsel to advise the department on matters pertaining to state and federal regulatory issues affecting the power-purchasing program when those interests conflict with the interests of the State Water Project.

- Conduct a comprehensive assessment of the department's collaboration with the attorney general, the Energy Oversight Board, the CPUC, and other state entities to assure that the interests of the power-purchasing program are distinctly and adequately represented in regulatory proceedings.

- Seek clear statutory authority to use financial instruments to manage gas and electric transaction risks.

To improve its ability to monitor the investor-owned utilities' performance in complying with the terms of the servicing agreements, the department should do the following:

- Amend the servicing agreements to include language that promotes accuracy in estimates of customer usage provided by the investor-owned utilities.

- Complete its efforts to ensure that it can account for all of the amounts it is owed by the investor-owned utilities, including the completion of its project to track power delivered to retail customers.

- Develop audit procedures to review periodically the investor-owned utilities' performance of critical elements in the servicing agreements, such as cash remittance methodologies, the allocation to customers of the investor-owned utilities of the power that the department purchases, and the cost of energy conservation programs.

- Coordinate with investor-owned utilities to develop audit procedures designed to detect noncompliance with the critical elements of the servicing agreements. These procedures can be performed by the investor-owned utilities' certified public accountants in conjunction with annual financial audits.

- Complete its efforts to execute agreements with the three investor-owned utilities that cover power purchases designed to balance in real time the electricity power supplied to the power grid with total customer usage.

To help ensure that its contractors do not have conflicts of interest, the department should continue its efforts to review all employees and consultants twice each year and it should retain a record of its review for each review period.

The department should improve its controls designed to have all power-purchasing program costs appropriately charged to the program and supported by evidence of service.

We conducted this review under the authority vested in the California State Auditor by Section 8543 et seq. of the California Government Code and according to generally accepted government auditing standards. We limited our review to those areas specified in the audit scope section of this report.

Respectfully submitted,

ELAINE M. HOWLE
State Auditor

Date: December 20, 2001

Executive Staff: Philip J. Jelicich, CPA, Deputy State Auditor
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APPENDIX A

Summary of the Department's Contracts and Agreements in Principle for Power

As of the end of October 2001, the Department of Water Resources (department) had entered into 55 long-term contracts and 2 agreements in principle to meet a portion of its net-short obligations. These contracts have terms that range from a few months to as long as 20 years and could cost ratepayers of the investor-owned utilities up to $42.6 billion over the 10-year period ending December 31, 2010.

Table 10 summarizes the principal business terms for each contract. The primary sources of this information were several department documents, including contract summary forms prepared by the contract negotiators, the department's contract tracking spreadsheet, and, in certain cases, the completed contracts themselves.

The Pricing Structure column of the table indicates how the power delivered under each contract is priced. The vast majority of the contracts have pricing structures that feature fixed prices. While some of these fixed-price contracts have separate capacity and energy charges, most have only energy charges. Contracts with capacity and/or energy charges that are fixed throughout the life of the contract are described as having a "fixed-flat" pricing structure. An example of a contract with a fixed-flat price structure is El Paso 1, which has a term of 5 years and an energy charge of $115 per megawatt-hour that does not change over the life of the contract. Contracts with charges that vary according to a fixed schedule are described as having a "fixed" pricing structure. An example of a contract with a fixed price structure is Calpine 2, which has a term of 20 years and separate capacity and energy charges. While the energy charge remains at $73 per megawatt-hour throughout the life of the contract, the capacity charge decreases from $90 million per year for each of the first 5 years to $80 million per year thereafter. In Table 10, the cost per megawatt-hour factors in capacity payments to arrive at the price shown. Certain contracts with fixed or fixed-flat capacity charges also have variable energy charges that change as the price of

natural gas changes. All of these gas-indexed contracts give the department the option of purchasing the gas used in the seller's generators. These contracts are referred to as "tolling" agreements.

The department's portfolio also includes one exchange agreement and two California Power Exchange (power exchange) block-forward market (PX-BFM) contracts. The exchange agreement with the Bonneville Power Authority does not specify volumes or prices but provides for the department either to return 1 megawatt-hour of energy for every megawatt-hour delivered by Bonneville Power Authority or to negotiate a purchase price. The PX-BFM contracts initially belonged to Pacific Gas & Electric and Southern California Edison but were seized by the State and assigned to the department after those two utilities failed to meet certain financial conditions set by the power exchange. We have assumed that the department will be required to compensate the power exchange for the market value of the seized capacity and energy.

The Dispatchable column indicates whether nor not the power covered by the contract is "dispatchable"—that is, whether the amount of energy delivered can be changed to meet the needs of the buyer. Most of the contracts entered into by the department are not dispatchable and thus require it pay for the contracted quantities even if the department does not need the power.

The Firmness column indicates the extent to which the seller guarantees the delivery of the power covered by the contract. The majority of the contracts provide for the delivery of "firm" energy. These contracts require the seller to provide energy in every hour of the delivery period, either from specified generators or from the market. Several contracts provide for "unit-contingent" or "system-contingent" sales. In a unit-contingent sale, the seller does not have to supply the power if the generating unit covered by the contract is not available. In a system-contingent sale, the seller does not have to supply the contracted power if its operating reserve drops below acceptable limits. Unit-contingent and system-contingent contracts thus pose more of a risk for the department. The portfolio also includes a number of contracts that provide for the delivery of "as-available" energy from resources such as wind, for which the generation is intermittent.

The Location column indicates where in the State the power is being generated, with NP 15 indicating power generated north of Path 15 and SP 15 indicating power generated south of Path 15. Path 15 is the main transmission connection between the northern

and southern parts of the State. It is significant because the State does not have sufficient transmission capacity to allow power to be easily sent between Northern and Southern California.

The Source column shows the source of the energy to be provided under the contract. Thermal generation is the source of most of the energy supplied under the contracts. Renewable and market resources account for very little of the delivered energy.

HOW OUR CONSULTANT COMPUTED THE POWER COSTS FOR THE CONTRACTS

Table 10 also provides an estimate of the power costs under each contract for the period ending December 31, 2010. In estimating these costs, our consultant, LaCapra Associates, made certain major assumptions, which we describe here. In addition to the department documents noted earlier, our consultant used data reported in the July 25, 2001, draft report titled "Power Supply Revenue Bonds" prepared for the department by Navigant Consulting Inc.

To determine the cost of each contract, our consultant multiplied the estimated capacity and energy purchases through December 31, 2010, by the appropriate capacity and energy charges. To simplify this calculation, our consultant assumed that the department would purchase the maximum amount of energy available under each contract, including all dispatchable contracts. A more accurate estimate would require the use of a detailed model that simulates the hourly operation of the generation and transmission resources within the Western Systems Coordinating Council region. Our consultant decided against performing that level of analysis, since it would have been extremely time consuming and because its estimates of energy purchased compare reasonably well with those estimated by the department's consultant using PROSYM, a proprietary model that dispatches generating resources within a power market to match the hourly demand and to minimize variable costs.

As we discussed in Chapter 2, some of the contracts include clauses that require the department to pay the cost of air emissions offsets that the seller must obtain in order to supply energy under the contract. In addition, some contracts provide for the pass-through of costs to upgrade emissions control equipment and emissions penalties. None of these emissions costs have been

included in the estimated power costs. Also excluded are the start-up and shut-down fuel costs that are recoverable under most tolling agreements.

Another key assumption is the cost of gas for the tolling agreements. Rather than develop an alternative price forecast, our consultant used the base case projection developed by Navigant Consulting Incorporated as reported in the "Power Supply Revenue Bonds" draft report mentioned earlier. That projection starts at $10.74 per million British thermal units in 2001 and falls to $4.68 per million British thermal units in 2010. Clearly, a different gas cost projection would change the power cost estimate.

Our consultant also assumed that the transmission system linking the northern and southern parts of the State is free of any constraints that would limit the department's ability to transfer surplus energy from the south to the north. As a result, our cost estimate does not include above-market costs associated with sales of excess energy at prices below the average cost of the portfolio. Finally, the two PX-BFM contracts included in the portfolio are valued in the cost analysis at $100 per megawatt-hour.

Our consultant did not project costs past 10 years because projections become less certain beyond that time and because the department has not attempted to do so either. Thus, costs could be higher. For example, Calpine 2, a 20-year peak contract, shows a value of $1.341 billion in the table, but when projected over 20 years, the value increases to $2.875 billion.

TABLE 10

Business Terms of Contracts and Agreements in Principle Signed by the Department

Supplier	Letter of Intent Date	Signed Contract	Pricing Structure	Start Date	Term in Years	Product*	Dispatchable?	Firmness	New Units?	Source	Location	MW Range	Ten-Year Energy Purchases (GWh)	Price Range ($/MWh)	Ten-Year Power Cost (Millions of $)
El Paso 1	2/7/01	2/13/01	Fixed flat	2/9/01	5.00	Peak	No	Firm	No	Unspecified	SP15	50	1,221	$115	$ 140
El Paso 2	2/7/01	2/13/01	Fixed flat	2/9/01	5.00	Peak	No	Firm	No	Unspecified	NP15	50	1,221	127	155
BPA	2/14/01	2/20/01	Fixed flat	2/13/01	1.25	Base	No	Firm	No	Import	NP15	18	139	55	10
Morgan Stanley	2/7/01	2/20/01	Fixed flat	2/15/01	5.00	Base	No	Firm	No	Market power	SP15	50	2,136	96	204
BPA	2/14/01	2/20/01	Exchange	2/20/01	0.83	Operating reserve	No	As available	No	Import	NP15	Unspecified	NA	NA	NA
Dynegy—Peak 1†	2/23/01	3/2/01	Tolling	3/6/01	0.83	Peak	No	System contingent	No	Thermal	SP15	1,000	4,094	101	402
Dynegy—Off-peak 1	2/23/01	3/2/01	Tolling	3/1/01	0.09	Off-peak	No	System contingent	No	Thermal	SP15	200	482	145	70
Williams B1	2/6/01	2/16/01	Fixed flat	4/1/01	10.00	Peak	No	Unit contingent	No	Thermal	SP15	175-300	10,006	87	871
Williams B2	2/9/01	2/21/01	Fixed flat	6/1/01	4.50	Peak	No	Unit contingent	No	Thermal	SP15	140-400	4,578	63	286
Williams A	2/9/01	2/21/01	Fixed flat	6/1/01	9.50	Base	No	Unit contingent	No	Thermal	SP15	35-600	21,983	63	1,374
Calpine 3	2/21/01	2/21/01	Fixed	7/1/01	10.50	Base	No	Unit contingent	No	Thermal	NP15	200-1,000	70,115	115-61	4,322
Calpine 2	2/21/01	2/27/01	Fixed	8/1/01	20.00	Peak	Yes	Unit contingent	Yes	Thermal	NP15	90-495	7,958	174-154	1,338
Calpine 1	2/6/01	5/25/01	Fixed flat	10/1/01	10.33	Base	No	Firm	No	Thermal	NP15	250-1,000	64,596	59	3,785
Dynegy—Base	2/23/01	3/2/01	Fixed flat	1/1/02	3.00	Base	No	Firm	No	Thermal	SP15	200	5,261	120	629
Dynegy—Peak 3	2/23/01	3/2/01	Fixed flat	1/1/02	3.00	Peak	No	Firm	No	Thermal	SP15	600	8,986	120	1,074
Dynegy—Peak 2	2/23/01	8/14/01	Tolling	1/1/02	3.00	Peak	Yes	System contingent	No	Thermal	SP15	1,000	14,851	103-79	1,376

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Supplier	Letter of Intent Date	Signed Contract	Pricing Structure	Start Date	Term in Years	Product*	Dispatchable?	Firmness	New Units?	Source	Location	MW Range	Ten-Year Energy Purchases (GWh)	Price Range ($/MWh)	Ten-Year Power Cost (Millions of $)
Dynegy—Off-peak 2	2/23/01	8/14/01	Tolling	1/1/02	3.00	Off-peak	Yes	System contingent	No	Thermal	SP15	200	1,747	$103 - $79	$ 162
Williams B3‡	None	2/21/01	Fixed flat	1/1/03	8.00	Peak	No	Unit contingent	No	Thermal	SP15	500	19,968	63	1,248
High Desert	2/28/01	3/15/01	Fixed flat	7/1/03	8.25	Base	No	Unit contingent	Yes	Thermal	SP15	840	51,896	58	3,010
Constellation	2/28/01	3/15/01	Fixed flat	4/1/01	2.25	Peak	No	Firm	No	Unspecified	SP15	200	2,246	154	346
Allegheny—A	2/26/01	3/26/01	Fixed flat	3/23/01	0.58	Peak	No	Unit contingent	No	Thermal	SP15	250	1,270	61	77
Allegheny—B	2/26/01	3/26/01	Fixed flat	10/1/01	10.25	Base	No	Unit contingent	No	Thermal	SP15	250-1,000	61,880	61	3,775
Primary Power	2/7/01	3/13/01	Fixed	6/1/01	2.50	Base	No	Firm	No	Renewable	SP15	16	362	100-90	34
PX-BFM	1/31/01	2/21/01	Market	3/1/01	0.83	Peak	No	Firm	No	Market power	NP15	500	1,962	Est. 100	196
PX-BFM	1/30/01	2/6/01	Market	4/1/01	0.75	Peak	No	Firm	No	Market power	SP15	925	3,463	Est 100	346
Alliance	2/26/01	4/24/01	Tolling	8/1/01	10.00	Peak	Yes	Firm	Yes	Thermal	SP15	80	1,468	379-141	253
Allegheny—C	3/26/01	4/27/01	Fixed flat	1/1/03	1.00	Peak	No	Firm	No	Thermal	NP15	150	749	76	57
Sempra Peak	2/28/01	5/4/01	Tolling>2002	6/1/01	10.30	Peak	No	Firm	Yes	Thermal	SP15	250-700	22,339	160-73	1,937
Sempra Base	2/28/01	5/4/01	Tolling>2002	4/1/02	9.50	Base	No	Firm	Yes	Thermal	SP15	150-1,200	70,986	87-57	4,302
Soledad	2/15/01	5/4/01	Fixed	5/1/01	5.00	Base	No	As available	Yes	Thermal	NP15	13	410	84-80	34
GWF Phase I,II, III	4/16/01	5/11/01	Tolling	9/1/01	11.33	Summer peak	Yes	Unit contingent	Yes	Thermal	NP15	88	23,713	295-44	1,690
Mirant	3/26/01	5/22/01	Fixed flat	6/1/01	1.50	Peak	No	Firm	No	Unspecified	NP15	500	3,952	149	587
Coral 1	3/16/01	5/25/01	Tolling>2005	5/24/01	11.25	Peak	No	Unit contingent	Yes	Thermal	NP15	100-400	13,520	245-57	1,219
Coral 2	3/16/01	5/25/01	Tolling>2005	7/1/03	11.25	Peak	No	Unit contingent	Yes	Thermal	SP15	175	5,049	169-57	347
Coral 3	3/16/01	5/25/01	Tolling>2005	7/1/02	10.00	Base	No	Unit contingent	Yes	Thermal	NP15	100	5,729	169-57	462
Coral 4	3/16/01	5/25/01	Tolling>2005	7/1/04	10.00	Peak	No	Unit contingent	Yes	Thermal	SP15	175	4,378	73-57	264

Supplier	Letter of Intent Date	Signed Contract	Pricing Structure	Start Date	Term in Years	Product*	Dispatchable?	Firmness	New Units?	Source	Location	MW Range	Ten-Year Energy Purchases (GWh)	Price Range ($/MWh)	Ten-Year Power Cost (Millions of $)
Pinnicale West	3/13/01	3/13/01	Fixed	6/1/01	0.33	Peak	No	Firm	No	Market power	SP15	90	140	$247	$ 34
Pinnicale West	3/2/01	3/2/01	Fixed	5/3/01	0.42	Off-peak	No	Firm	No	Market power	SP15	100	121	164	20
PacifiCorp	2/12/01	7/7/01	Fixed flat	7/1/01	10.00	Base	No	Unit contingent	Yes	Thermal	NP15	150-300	21,900	70	1,533
Sunrise CT	3/2/01	6/26/01	Tolling	8/1/01	1.42	Super summer peak	Yes	Firm	Yes	Thermal	SP15	325	447	228-212	97
Sunrise CC	3/2/01	6/26/01	Tolling	3/1/03	8.58	Base	No	Firm	Yes	Thermal	SP15	560	38,441	59	2,121
Cal Peak[II]	2/28/01	5/7/01	Tolling	10/15/01	10.00	Super summer peak	Yes	Unit contingent	Yes	Thermal	NP15	144	2,154	114-66	170
Cal Peak[II]	2/28/01	5/7/01	Tolling	10/15/01	10.00	Super summer peak	Yes	Unit contingent	Yes	Thermal	SP15	192	2,873	113-67	228
Whitewater Hill	5/8/01	7/27/01	Fixed flat	1/1/02	12.00	Base	No	As available	Yes	Renewable	SP15	65	1,936	60	116
Cabazon	5/8/01	7/27/01	Fixed flat	1/1/02	12.00	Base	No	As available	Yes	Renewable	SP15	43	1,328	60	80
Calpine—SJ	5/15/01	6/11/01	Tolling	5/1/02	3.00	Peak	Yes	Firm	Yes	Thermal	NP15	180-225	3,024	134-84	322
PG&E	4/24/01	6/1/01	Fixed flat	10/1/01	9.75	Base	No	As available	Yes	Renewable	SP15	66	2,017	59	118
Clearwood	None	6/22/01	Fixed flat	6/1/02	10.00	Base	No	Unit contingent	Yes	Renewable	NP15	25	1,692	67	114
Wellhead—Fresno	6/21/01	8/7/01	Tolling	8/20/01	10.33	Peak	Yes	Unit contingent	Yes	Thermal	NP15	21	950	179-92	100
Wellhead—Panoche	6/21/01	6/21/01	Tolling	9/15/01	10.33	Peak	Yes	Unit contingent	Yes	Thermal	NP15	50	2,218	142-78	194
Wellhead—Gates	6/21/01	6/21/01	Tolling	9/23/01	10.25	Peak	Yes	Unit contingent	Yes	Thermal	NP15	41	1,830	142-78	160
Capital Power	5/11/01	8/24/01	Fixed	11/15/01	5.00	Base	Yes	Unit contingent	Yes	Renewable	NP15	15	590	119-109	67

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Supplier	Letter of Intent Date	Signed Contract	Pricing Structure	Start Date	Term in Years	Product*	Dispatchable?	Firmness	New Units?	Source	Location	MW Range	Ten-Year Energy Purchases (GWh)	Price Range ($/MWh)	Ten-Year Power Cost (Millions of $)
Santa Cruz City	8/16/01	9/19/01	Fixed flat	3/31/02	5.00	Base	No	As available	Yes	Thermal	NP15	3	112	$65	$ 7
City of Lodi§	8/16/01	NA	Tolling	6/1/02	15.00	Base	Yes	Firm	Yes	Thermal	NP15	43	3,128	87-57	198
Turlock§	8/14/01	NA	Tolling	6/1/02	15.00	Base	No	Unit contingent	Yes	Thermal	NP15	25	3,864	103-62	234
LADWP#	8/17/01	NA	Tolling	7/1/01	0.25	Base	No	System contingent	No	Thermal	NP15	500	1,104	162	178
InterCom—Phase I	7/19/01	8/24/01	Fixed flat	9/1/01	2.00	Peak	No	Firm	Yes	Thermal	NP15	200	1,917	$45	86
Total															**$42,559**

Note: From a technical perspective, the department's records reflect that there are actually 38 contracts with 36 different counterparties. Under these 38 contracts, there are 58 separate transactions for power. For purposes of our report, we describe each transaction as a contract. The table above totals 57 contracts and differs from the number of 59 contracts that is often stated because the department treats each of the Cal Peak contracts as two contracts for the reason stated in footnote‖.

* See the Product Codes box below for description of the products purchased.

† May not be available all hours due to prior obligations.

‡ Up to 500 megawatts at the discretion of the seller.

‖ The department treats this contract as two transactions by separating the power between parts of the year.

§ Negotiations not complete. The Turlock power cost estimate is based on the proposed price terms for Lodi.

Subsequent to the audit's release, we learned that the department did not complete this contract. Effective February 20, 2002, the second and third columns have been changed from 6/29/01 and 6/19/01 to 8/17/01 and NA, respectively. In addition, a reference to the contract was deleted from the first footnote above. However, because the cost and megawatts of this transaction are insignificant, its inclusion has a negligible effect on our calculations and no impact on the conclusions reached in the report.

Product Codes	
Base	7x24—24 hours a day, 7 days a week, year round (approximately 8,760 hours)
Peak	6x16—Hours from 6 am to 10 pm, 16 hours a day, 6 days a week (Monday through Saturday), year round (approximately 5,000 hours)
Operating reserve	Capacity and energy transactions for the purpose of preserving power system reliability
Off-peak	8 hours per day not picked up by 6x16 peak product, and all hours on Sundays (approximately 3,760 hours)
Summer peak	6x16—Hours from 6 am to 10 pm, June 1 through October 31, 6 days a week (approximately 2,100 hours)
Summer super peak	5x8—June 1 through October 31, 8 hours a day, 5 days a week (approximately 870 hours)

APPENDIX B

Analysis of Troubling Contract Provisions

Three of the largest long-term contracts (Calpine, Williams, and Dynegy), all of which were executed quite early in the contract negotiation process, contain a number of troubling provisions. Provisions in two areas—the allocation of the cost risks of future government action and assurances that the new electrical generation that the Department of Water Resources (department) is paying for will actually be built and maintained—are especially noteworthy because they are particularly unfavorable to the department in these early contracts and because they were handled much better in contracts executed later in the process.

Because more than 80 percent of the total agreements in principle (based on gigawatt-hours) were executed within the first month of the process, it is difficult to isolate the time variable and do a real "apples to apples" comparison between the early and late contracts. The later contracts are typically much smaller than the early ones, and they were executed with much of the net short already under contract. As a result, the department was arguably less desperate for the later contracts and therefore had greater bargaining leverage. Nonetheless, we note that the Coral contract, which is a large contract executed later in the process, contains provisions that the three early contracts lack in both of the areas we have identified.

ALLOCATION OF RISK OF FUTURE GOVERNMENTAL ACTION

Generally, power purchase agreements allocate risks by the point of delivery. That is, all costs up to the point of delivery are borne by the seller, and all costs after the point of delivery are borne by the buyer. In several of the 13 contracts executed during the intense contracting period, this allocation of cost risks was changed.

Under the Williams and Dynegy contracts, the cost risks arising for air emissions laws and regulations were shifted to the department, and under the Calpine and Williams contracts, the cost risk of new governmental charges was shifted from the suppliers to the department.

In the Dynegy contracts, the parties contractually agree that Dynegy could not supply power to the department and stay within air emissions limits set by federal and/or state environmental agencies. To remove this potential regulatory obstacle for Dynegy, the department agreed to several rather drastic measures that removed any risk that Dynegy's emissions or environmental costs would increase at any time over the course of this 3-year agreement (and in some cases beyond).

First, for calendar year 2001, the department (1) acknowledged that Dynegy's existing obligations to supply power had already exhausted Dynegy's 2001 air emissions limits, (2) acknowledged that supplying the department with power could cause Dynegy to exceed its air emissions limits, and (3) agreed that the department would bear "any and all costs associated with exceeding such limits."

Second, the department acknowledged that supplying the power to the department over the remaining term of the contracts could cause Dynegy to exceed its emissions limits. The department agreed to bear all of those costs as well, "to the extent such are attributable to the performance of this agreement during that period." There is no apparent method for determining which air emissions costs are "attributable" to supplying the department's power versus the power Dynegy intends to provide to other purchasers. In view of the potential costs to the State, establishing a contractual method to determine these costs could have helped avoid disagreements that might arise in the future.

Third, as an additional catch-all guarantee of cost stability for Dynegy, the department agreed that if performing the contracts restricts the ability of Dynegy (or its affiliates) to generate electricity "during or beyond" the term of its contracts with the department, the department must "provide [Dynegy] with energy in quantities sufficient, and at appropriate times, to ensure that [Dynegy] and its affiliates are kept whole financially with respect to such restrictions." This means that if Dynegy's ability to produce and supply power is restricted in *any* way for *any* reason related to the performance of its contracts with the department, the department must provide power to Dynegy (rather than receive it) for an

undetermined period of time after the end of the contracts. The scope of events that could trigger this extremely broad and uncapped obligation for the department is unclear at present.

On the surface, one could argue that these provisions, while favorable to Dynegy, are reasonable. At the time that these agreements were being negotiated, Dynegy could not produce additional energy without running afoul of environmental regulations and, accordingly, if the department wanted the power, it would have to pay these increased costs.

Beyond the potential social and environmental implications inherent in this justification, our analysis of these provisions is that they are far broader than perhaps was intended by the department. The department is responsible for costs or restrictions imposed by *any* environmental agency at any time over the life of the contracts. During the first year of the contracts (2001), the department is deemed responsible for 100 percent of these costs, whether its contracts cause Dynegy to exceed its limits or not. Thereafter, for the life of the contracts, the department pays for Dynegy's costs relating to air emissions to the extent that those costs are "attributable" to performing the contracts. At best, determining what costs are "attributable" to the department's contracts seems ripe for litigation. At worst, 100 percent of air emissions costs—those stemming from the full number of gigawatt-hours delivered under contracts between Dynegy and the department—could be deemed "attributable" to the department's contracts, even if the department's contracts were executed before other Dynegy contracts that cause Dynegy's air emissions costs to increase.

To illustrate the importance of understanding the potential cost risks associated with passing the emissions costs on to the department, we calculated the potential cost risk under the Williams contract. The average price for air emission credits in 1991 was $4,284 per ton; during the first months of 2000 it increased tenfold to $45,000 per ton and was capped by the South Coast Air Quality Management District Governing Board at $15,000 per ton beginning in January 2001. Given this per-ton cap (and assuming that it remains capped at this level for the foreseeable future), the contracts with Williams, for example, expose the department to between $400 million and $688 million in potential emissions credit pass-through costs over the life of the contracts.

This broad range of exposure results because the contracts identify the source units for the power in the short term but thereafter give Williams the discretion to designate the unit(s) that will generate power for the department. Because not all of the Williams-owned units have equal emission rates, the potential exposure varies depending on which units Williams decides to use to generate the department's power. If William's agreements with other purchasers do not contain similar provisions allowing the pass-through of emissions costs, Williams will have no incentive to use the units with the lowest emission rate to produce the department's energy. To the contrary, the contracts provide an incentive for Williams to generate the department's power using the units with the highest emission rates because those costs are recoverable from the department.

While no air emissions credits were passed on in 2001, a significant unanswered question remains as to whether all or some portion of the potential $688 million in emissions costs—which would amount to an increase of more than 18 percent in the approximately $3.8 billion cost of the Williams contracts—will be passed on to the department over the remaining 8-plus years of the contract.

The provision requiring the department to supply Dynegy with power is very broad and appears not to consider that, although the contracts are effective until December 31, 2004, the department loses its authority to purchase power under the program as of January 1, 2003. Thus, in addition to creating a potentially significant and presently unknowable burden on the department, this provision may be impossible for the department to comply with unless it diverts some of the other energy that it has under contract away from the utilities serving California's consumers and instead supplies that energy to Dynegy sufficient to make Dynegy and its affiliates "whole financially," however that phrase is to be defined either by the parties or by a court.

The Williams contract executed in February 2001 contains provisions that shift the risks of increased costs due to future governmental action onto the department in a particularly onerous way. The typical energy contract allocates the risk of increased costs with reference to the delivery point: The seller bears the risk of such increased costs up to the delivery point, and the buyer bears those risks beyond the delivery point. Some of the long-term power-purchase contracts shift what typically would be the seller's cost risks onto the department. How burdensome such cost shifting is for the department depends on three issues:

1. Does the provision make the department responsible for costs created by governmental actors other than itself and, if so, how closely are those governmental actors related to the department?

   For example, an increased cost of service could be due to the action of the department itself (if, for example, the department raises the rates for the water that the seller uses to produce steam in a generating plant), of a governmental actor closely associated with the department (for example, another natural resources agency of the State, such as an air resources board that regulates a seller's emissions), of a California governmental actor more distantly related to the department (such as a local government that imposes property taxes on the seller's generating plant), or of a non-California governmental actor (for example, if the federal government imposes a tax increase, whether related or not to the generation and sale of electricity).

   The more attenuated the relationship between the department and the governmental actor ultimately responsible for the increased cost of service, the more burdensome it is on the department to make it bear the cost risk, because the department has less practical ability to manage the risk. In other words, to keep costs down, the department will need to actively monitor and oppose governmental decisions that could increase its costs under the power contract. Monitoring and opposing governmental decisions by remote governmental actors is inherently more difficult than dealing with in-state governmental actors. Accordingly, such provisions are more burdensome on the department simply by virtue of casting a wider net that encompasses a broader array (and therefore a broader risk) of future governmental charges.

2. Does the provision expose the department to the risk of increased costs imposed indirectly on the seller due to governmental action with direct effects on third parties, or does it expose the department to the risk of only those increased costs imposed directly on the seller?

   All of the cost increases discussed in the previous paragraphs are ones directly imposed on the seller by governmental action. By contrast, an example of an increased cost of service imposed indirectly on a seller would be a tax increase on fuel that fuel suppliers pass along to power generators as buyers of fuel. The increased fuel cost is an increased cost of service for the power seller, but it is not a cost imposed directly on that seller by

governmental action; it comes indirectly through the governmental decision that increases the costs charged by fuel suppliers. Making the department take the risk of such indirect cost increases is more burdensome than limiting the department's exposure to direct cost increases, because a wider array of governmental action potentially affects the department's obligations.

3. Does the provision shift all of the cost risk onto the department, or does it shift only some of the cost risk?

   A provision that makes the department responsible for "any" increased costs of service shifts all of the risk of future governmental action onto the department, whereas a provision that makes the department responsible only after the increased costs of service exceeds some threshold amount shifts only part of the risk onto the department. A provision that shifts all of the risk onto the department is obviously more burdensome than one that shifts only some of the same risk onto the department.

The Williams agreement is striking in that in all three of these respects it is almost as burdensome for the department as it could possibly be, as we explain next.

The Williams Governmental Charges Provision Makes the Department Potentially Responsible for Acts by any Governmental Actor, No Matter How Remotely Removed From the Department or California

The Williams provision makes the department responsible for paying the increased costs of service in two instances: (1) cost increases that result from "any governmental action or inaction *other than by a Governmental Entity*" and (2) increases that result from "*any action or inaction by a Governmental Entity*." The Williams agreement amends the Edison Electric Institute (EEI) form Master Agreement to include the following definition of the term "Governmental Entity": "a public power system, the State of California, any municipality, county, governmental board, public power authority, public utility district, joint action agency, or other similar political subdivision or public entity of the State of California, the State of California Department of Water Resources, or any combination thereof." In other words, neither governmental actors outside of California nor private actors qualify as a "governmental entity." Limiting the definition of "governmental entity" to California governmental entities could have made the

department's ability to control cost risks more manageable because then the department would have to monitor the actions only of governmental actors within the State.

However, the department's cost risks are not limited to actions by California governmental entities but also include actions by some governmental entity outside of the State. Given the way that the terms are defined in the Williams contract, two types of cost increases potentially qualify as increases due to governmental action by a non-California governmental entity: (1) cost increases that are simply pass-throughs by third parties of specific governmental charges imposed on them—for example, increases in fuel prices due to a new or increased fuel tax, and (2) cost increases due to more general action by governments outside of California—for example, new taxes imposed by the federal government.

Under the terms of the Williams agreement, "government action that increases the costs of service" includes not only taxes but also "the imposition of other unanticipated costs and charges caused by government action." Thus, if Williams's costs of service increases because, for example, the federal government imposes a tax on sellers of fuel, causing its fuel costs to increase, the seller's imposition of a cost increase on Williams arguably would qualify as a governmental action that increases the costs of service, albeit one not directly taken by a California governmental entity. In other words, the Williams contract passes the cost risk of any governmental action to the department, regardless of whether the increased cost resulting from the governmental action is imposed directly or indirectly on the power supplier and regardless of whether the governmental action is by a California governmental entity or some other governmental actor outside of the State.

The Williams Governmental Charges Provision Makes the Department Potentially Responsible for Cost Increases Caused Only Indirectly by Governmental Action

As we explained in the previous section, "governmental action that increases the cost of service" is defined to include any cost increase that results from direct government action. In other words, the governmental charges provision in the Williams contract would capture cost-of-service increases like a fuel-cost increase due to a tax on fuel suppliers, including those imposed by a California governmental entity or any other governmental actor outside of the State.

The Williams Governmental Charges Provision Potentially Shifts Onto the Department All of the Risk of Cost Increases Resulting From Governmental Action by California Government Entities but Only Some of the Risk of Cost Increases Resulting From Some Other Governmental Actor

Under the terms of the Williams agreement, "if [Williams] can demonstrate that its cost of service for this agreement has been increased since the effective date as a result of any action or inaction by a governmental entity," the department is obligated to pay the entire increased cost or reimburse Williams for it. In other words, the department is responsible for all of the increased costs attributable to action by the State or its political subdivisions, the entities defined as "Governmental Entity." By contrast, there is a $5 per megawatt-hour threshold that must be reached before the department is responsible for increased costs "as a result of any governmental action or inaction other than by a California Governmental Entity." If Williams' costs of service increase due to action by some government other than a California governmental entity—for example, the federal government—the department is responsible only if the aggregate cost increase over the life of the contract exceeds $5 per megawatt-hour, and then only for that portion in excess of $5 per megawatt-hour.

These provisions create some ambiguity regarding the threshold that applies to increases that are due to pass-throughs by private third parties of governmental charges imposed by California governmental entities. One way of looking at such charges is that they result from government action of a California governmental entity and therefore are not subject to the $5 threshold. The other way of looking at those charges is that the imposition of the cost increase is not by the California governmental entity but by the third party, since the contract defines "governmental action that increases the cost of service" to include impositions merely "caused by" government action, and that therefore the increase is subject to the $5 threshold.

The Williams agreement is notable finally for the broad array of relief it offers Williams for costs due to government action. Not only is the department required to reimburse Williams for the costs of such government action, but Williams has the option to declare an event of default, terminate the agreement, and collect the termination payment if "any action or inaction by any California Governmental Entity shall . . . have any adverse impact on or otherwise limit or alter adversely the economic benefits and

burdens conferred on [Williams]." This provision gives Williams almost unfettered discretion to walk away from the contract in the face of any action or inaction by any of the California actors defined as government entities, and it exposes the department to the substantial risk not only that it might bear the cost of increases in Williams's costs of doing business due to events as remote as local property tax increases or increases in rates for worker's compensation insurance, but that, in a rising energy market, Williams might seize on one of these remotely related government actions to claim that a default has occurred, terminate its contract with the department, and take advantage of the higher market prices.

ASSURANCES THAT NEW GENERATION WILL BE BUILT AND MAINTAINED

During the intense contracting period, the department entered into three contracts with Calpine, one of which was the 20-year Calpine Peaker (Calpine Peaker 2) contract for new construction of a 495-megawatt peaker plant. In the spring Calpine proposed a smaller but similar deal for a 3-year contract with 180 to 225 megawatts, and Calpine used the Calpine Peaker contract executed in February as the basis for the new deal (the Calpine SJ agreement).

Generally, when we compared the early contracts to the later contracts, we noticed the later contracts had significantly better reliability protections for the department. For example, in the later Calpine SJ contract, we found that although Calpine proposed a deal that generally lacked reliability provisions, the department was able to negotiate significantly better reliability provisions in the final deal. We asked the department whether advice from their legal consultants had prompted these improvements. While the department received advice from its legal consultants on these contracts, just as it had on the other long-term contracts, the department asserted attorney-client privilege as to the contents of any communications it received from its legal consultants on these long-term contracts. Thus, we cannot disclose the contents of any such communications.

The capacity payment provisions in the Calpine Peaker 2 contract (referred to as Calpine 2 in Table 10) are notable for how poorly they protect the State's interests. The Calpine Peaker 2 is a 20-year contract for 495 megawatts of peaking capacity (2,000 hours per year, schedulable during 7 months of the year at peak hours). The scheduled power is to be delivered from 11 plants, each with

a capacity of 45 megawatts. Those plants are expected under the contract to achieve commercial operation at various times during the first contract year (August 2001 through August 2002).

Calpine's obligation to deliver power is contingent on the various units achieving commercial operation. For example, if one of the 11 units fails to achieve commercial operation at all, the department will arguably have the right to schedule only 450 megawatts of peak power rather than the full 495 megawatts. In other words, the amount that the department is allowed to schedule from Calpine would be reduced by the total capacity (45 megawatts) of the one unit that failed to achieve commercial operation.

Once a unit achieves commercial operation, that unit's capacity (45 megawatts) is available to the department (at the appropriate peak times) on a unit-contingent basis for its first six months of commercial operation. "Unit contingent" means that Calpine has to deliver the power from its own unit only and that delivery from the unit is excused for forced outages or other events outside of a seller's control. For example, assume that the 11th unit achieves commercial operation and within the first 6 months it experiences an unscheduled outage. Because the capacity of that unit is available to the department on only a unit-contingent basis, the department would have the right to schedule only 450 megawatts of power rather than 495 megawatts from Calpine under the contract. Once a unit has been in commercial operation for 6 months, the department has the right to schedule power equivalent to that unit's capacity on a firm basis. This means that, absent force majeure, the department has the right to schedule that unit's output or, if that unit should be unavailable, power equivalent to what that unit would have otherwise provided. In other words, Calpine would be obliged to obtain that capacity on the market and provide the power to the department.

The pricing of this power consists of two components: an energy charge and a capacity charge. The department pays the energy charge only for the megawatt-hours that it actually schedules from Calpine under the contract; the price is $73 per megawatt-hour. In addition to paying Calpine for the energy the department schedules, the department must pay Calpine annual capacity payments of $80 million to $90 million in exchange for having the capacity available. The department is obliged to make those capacity payments regardless of whether Calpine actually delivers the power to the department. This provision is not alarming; capacity payments typically operate in that way. The troubling aspect of the capacity payment provisions is that typically capacity

payments are contingent on the seller having the units (or capacity) available to produce the power. However, in the Calpine contract that requirement is not expressly stated after the first year of the contract. Thereby, subjecting the department to the legal risk that Calpine may attempt to assert that the department is obliged to make the capacity payments (in all years other than the first year) regardless of whether any of the 11 units the department is making capacity payments on are actually available to produce power.

The department's obligation to make these capacity payments regardless of whether the capacity of the designated units is actually available subjects the department to three interrelated risks:

- That the department will have to make capacity payments in the full amount even though fewer than all 11 units ever achieve commercial operation.

- That the department will have to make capacity payments in the full amount even though some or all of the 11 units are taken off-line after initially achieving commercial operation.

- That there is not enough supply, and Calpine cannot purchase the substitute power.

The department attempted to manage the first risk, but the provisions that it put in place do not clearly and unambiguously protect the department. Calpine initially proposed that the department make annual capacity payments of $90 million for each of the first 5 years and $80 million in each of the remaining 15 years; these payments were not predicated in any way on the actual availability of capacity. The department counter-proposed that the capacity payments in the first year be reduced on a pro rata basis to the extent that less than 495 megawatts of capacity was available to it. (Calpine had the option to make available the full 495 megawatts of capacity from units other than the 11 units to be built and thereby be entitled to the full $90 million capacity payment.) The final agreement contains a provision for a pro rata reduction for the first year. The main problem with this provision is that it expressly protects the department only in the first year of the contract but not in later years. Nonetheless, if commercial operation of all 11 units is achieved on schedule within the first contract year, the department will be better protected. However, if that does not occur, there is a legal risk that the department is not protected against having to make capacity payments in the following years for power plant capacity that does not come on-line.

In addition, permitting Calpine to provide substitute power displays inattentiveness to this risk. When a goal of a contract is to coax a seller into building new power plants, it is especially important for the State not to permit sellers to substitute power obtained from other sellers for the power the seller should be providing from its own power plants. The point of the contract is not merely to obtain a certain amount of power, it is to create new power supplies, increasing the overall amount of power in the market, in the hope of stabilizing prices. If the State were to give a seller beneficial terms (either as to price, duration of the contract, or security of payment), partly in consideration for the seller increasing the California energy supply, the State would deprive itself of the benefit of that bargain if it were to permit the seller to fulfill the contract out of existing energy supplies from the market.

Assuming that all 11 units achieve commercial operation on a timely basis and remain in commercial operation for 6 months thereafter, Calpine will be obliged to provide 495 megawatts of firm energy as scheduled by the department, regardless of whether the initially designated 11 power plants produce and provide the power. In effect, therefore, what the department has received in exchange for its capacity payment is an option to purchase, each year, 495 megawatts multiplied by 2,000 hours of energy at a price of $73 per megawatt-hour. What the department does not receive in exchange for these capacity payments is express assurance that the overall energy supply in California will be increased by keeping the 11 units ready to produce and supply power. To the extent that these substantial capacity payments were agreed to in an effort to promote the State's interest in increasing the overall energy supply, the purpose was not expressly achieved. To clearly achieve that purpose, it would have been necessary to expressly tie the amount of the capacity payments to the actual availability of the 11 units to produce and supply power for all 20 years of the contract.

In contrast, the Calpine SJ agreement, entered in June 2001, protects these state interests much better. The Calpine SJ agreement calls for the construction of four power plants. Like the Calpine Peaker 2 contract, the Calpine SJ contract is a peaking-capacity contract that contains both an energy charge and a capacity charge. Unlike the Calpine Peaker 2 contract, however, the Calpine SJ contract expressly protects the State in the event that the units are not brought into commercial operation in the first instance, and in the event that after achieving commercial operation, they suffer unscheduled outages.

The Calpine SJ agreement allows the department to terminate the contract with respect to any units that fail to achieve commercial operation by a particular target date. The effect of termination under those circumstances is to reduce the overall power available to the department under the contract by the amount of power that the canceled unit would have supplied. Because the capacity payment is expressly tied to the overall power available to the department under the contract from each unit, the cancellation of a unit clearly reduces the amount of the capacity payment that was attributable to that unit. In this way, the department better protects itself against paying a full capacity payment when its goal of bringing new power plants on-line is not met.

Similarly, the Calpine SJ agreement protects the State's interest in assuring that the plants not only come on-line in the first instance but that they remain on-line, increasing the overall power supply in California. The Calpine SJ agreement provides that the capacity payment will be reduced if Calpine fails to achieve set (seasonally adjusted) availability factors; in other words, if the plants are not producing the full amount of power anticipated in the contracts, the payment is reduced. Moreover, the contract requires that capacity be verified by physical tests once per year and gives the department the right to have the units physically tested twice more per year. Thus, the department is not required to pay for capacity that it thought it would receive but did not in fact receive. In this way, it better protected itself against paying a full capacity payment when its goal of keeping new plants on-line was not being met.

The contracts that the department executed with Coral in May 2001 contain similar protections for the department. Those contracts contemplate delivery of "base quantities" of power and "additional quantities" consisting of two deliveries of 175 megawatt-hours for each peak hour for 8 to 9 years. The contract permits Coral to cancel either or both of these "additional quantities," but unless the cancellation is due to a change in the law materially affecting Coral's air emissions costs or to its inability to obtain permits necessary for construction, Coral must pay the department $5 million for each such cancellation.

The Coral contracts contemplate construction of five new 43-megawatt facilities and capacity payments of $358,000 per month for each generating facility that has achieved commercial operation. There are target dates for major milestones, and the

department is entitled to progress reports, which increase in frequency if deadlines are missed. The department also has the right to declare an event of default and terminate the contract if the financial guarantor becomes uncreditworthy and Coral fails to procure a replacement guarantor, a right infrequently granted to the department in these contracts.

In contrast to the Calpine Peaker 2 contract, the Coral contracts do not require the department to begin making capacity payments until the unit achieves commercial operation. The contract also provides meaningful penalties if Coral fails to achieve commercial operation of all of the units by specific deadlines: The capacity payment for each facility that does not achieve commercial operation by October 31, 2001, is reduced by 6 percent in each month that the capacity payment is payable. After June 1, 2002, the capacity payment is reduced by 12 percent in each month that the capacity payment is payable. Thus, in addition to forfeiting the $358,000 for each month that the unit remains inoperable, once the unit becomes operational, Coral is penalized $21,480 per month for the life of the contract for each unit that fails to achieve commercial operation by October 31, 2001, and a total of $42,960 per month for each unit that does not reach commercial operation by June 1, 2002.

The Coral contract provides additional incentives for Coral to provide reliable power by requiring it to make guarantees that the power will be available. In addition to requiring Coral to pay cover damages for the cost of replacement power, the contract provides that, if the actual availability during the peak and nonpeak periods is less than 97 percent and 94.3 percent, respectively, Coral must pay the department 2 percent of the capacity payments the department made for each full percentage point that the actual availability is lower than these targets.

The Calpine Peaker 2 contract, which was agreed to on February 27, 2001, does not require Calpine to operate and maintain the units in accordance with prudent industry practice. These provisions are necessary to protect the State's interest that the identified power plants remain on-line, since imprudent operation and maintenance can lead to unnecessary unscheduled outages. The State has two different interests in avoiding such unscheduled outages:

- When the department purchases unit-contingent power, unscheduled outages relieve the seller of any obligation to deliver power at all during the outage; therefore, the prudent

operating requirements promote the reliability of the supply of unit-contingent power. The department did get a "prudent industry practices" provision in the February 26 contract with Calpine (February 26 Calpine contract) for 9.5 years of unit-contingent power.

- When the department contracts not just to receive power but to have new power plants built, unscheduled outages impair the State's goal of increasing the available energy supply in California; therefore, the State wants to ensure that power plants it expects the seller to build will remain on-line once they are built. The prudent operating requirements further that goal. Again, in the February 26 deal with Calpine, which did contemplate new power plants being built, the department successfully negotiated an express "prudent industry practices" provision.

The question arises as to why the department successfully negotiated an express prudent industry practices provision in the February 26 Calpine contract but not in the February 27 Calpine Peaker 2 deal, when the provision appears to be necessary in both deals to protect the State's interests. In part, the absence of such a provision in the February 27 Calpine Peaker 2 deal may be due to the fact that affiliates of Calpine, rather than Calpine itself, were to be the owners of the plants designated in the February 27 Calpine Peaker contract. Calpine might have been unwilling to guarantee the conduct of owners that Calpine did not control. That said, however, the department got similar provisions from other sellers that did not own particular power plants. For example, in the Coral contract, the new power plant in question was being developed by an affiliate of Coral, not by Coral itself. Nevertheless, Coral promised to use "commercially reasonable efforts" to cause the owner to secure the permits and environmental offsets necessary for the plants to operate so as to meet the department's demands under the contract. Moreover, Coral promised that each power plant will be maintained in accordance with prudent industry practices.

The Calpine Peaker 2 contract also does not provide the department with the right to terminate the contract (no "off ramp") in cases of repeated or deliberate failure by Calpine to deliver. Such failure gives the department a right only to cover damages; it is not an event of default giving rise to a right of termination. As we discuss in Chapter 2, the exclusive reliance on cover damages may be appropriate for a purchaser in a pure commodity transaction

in a well-functioning market, but it is not appropriate for a purchaser like the department with an obligation to purchase the energy necessary to serve retail load in a crisis market.

The key shortcomings in the Calpine Peaker 2 contract are remedied in the Calpine SJ contract executed in June 2001:

- Calpine is expressly not allowed to substitute power from other suppliers, except for a brief period prior to the drop-dead deadline for bringing the designated plants into commercial operation or in cases of "forced outage," "force majeure," or when the capacity of the units is needed to serve new load at the associated U.S. DataPort North San Jose Project.

- The contract contains availability standards and the capacity payment is reduced if those availability standards are not met; similarly, the contract provides for a reduction of the capacity payment if a unit is not constructed or brought into commercial operation on schedule.

Like the Calpine Peaker 2 contract, the Calpine SJ agreement does not require prudent industry practices as to operation and maintenance. The plants designated in the Calpine SJ contract, like the ones in the Calpine Peaker 2 contract, are to be owned by affiliates of Calpine rather than by Calpine itself. The key concern driving the need for prudent industry practices—namely, the concern that the units will be off-line too often due to imprudent operation and maintenance—is protected against by making the capacity payment contingent on the actual availability of the power plants to supply power. In other words, Calpine has incentives in the Calpine SJ contract that it does not have in the Calpine Peaker 2 contract to make sure that the units remain running and are available to supply power to the department.

Finally, while the Calpine SJ contract is an improvement over the Calpine Peaker 2 contract, it is not perfect, and it has limitations that are also found in the Calpine Peaker 2 contract. Like the Calpine Peaker 2 contract, the Calpine SJ contract does not provide any right to terminate for repeated or persistent failure to deliver. This is less of a concern in Calpine SJ than it is in the Calpine Peaker 2 contract primarily because Calpine SJ expressly ties the amount of the capacity payment to the actual availability of the units to supply power; there is not the risk in Calpine SJ (as there is in the Calpine Peaker 2 contract) that the department will be forced to pay for power capacity that is not available to it. In other words, Calpine SJ, unlike the Calpine Peaker 2 contract, at

least provides some penalty for failure to deliver power (loss of capacity payments), but neither agreement contains the more desirable penalty: a right of termination in favor of the department for repeated failures to deliver power.

Similarly, Calpine SJ, like the Calpine Peaker 2 contract, excuses Calpine from its obligation to deliver unit-contingent power if the output of a designated power plant is reduced or curtailed "for any reason." The department is more exposed to the risk of such reductions in Calpine SJ than in the Calpine Peaker 2 contract because the Calpine SJ product is unit-contingent for the entire 3-year life of the contract, whereas it is unit-contingent for only the first 6 months of each unit's commercial operation in the Calpine Peaker 2 contract. However, where performance is excused for such reductions or curtailments, the department gets a reduction of the capacity payment in Calpine SJ that it does not get in the Calpine Peaker contract.

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APPENDIX C

Report Card for Individual Contracts Reviewed

This appendix, which takes the form of a report card, summarizes the terms of the long-term power-purchase contracts entered into by the Department of Water Resources (department). We graded the contracts based on their (1) reliability of delivery, (2) reliability of availability, (3) reliability in the development of new generation, (4) potential for cost increases, (5) proper balancing of tolling agreement risks, (6) flexibility for the department to renegotiate onerous terms, and (7) assignment flexibility. Using a –1 to +1 scale, we assigned grades to the contracts for each of these categories as follows:

–1 indicates contracts that are unfavorable to the State

0 indicates contracts that are neutral to the State's interests

+1 indicates contracts that are favorable to the State

In some instances, not all grades are used for a given category. For example, in certain situations the presence of a particular contract term can make the contract more favorable to the State, but its absence does not make the contract less favorable.

Our report card analysis was far less rigorous than our detailed analysis of the contracts within the audit sample, and the results make no distinction between contract provisions other than good, neutral, or bad. (For example, the Calpine provision requiring the department to pay for any increase in Calpine's cost of service over 50 cents per megawatt-hour, while qualitatively worse, receives the same –1 for the price risk category as a provision requiring the department to pay for any increase in taxes directed at new generation.) Overall, however, grading the contracts reaffirmed our conclusions from the more in-depth analysis of the audit sample contracts. The large contracts executed prior to March 2001 may not achieve the Assembly Bill 1X goals of ensuring reliable power, and the contracts that do contain better reliability guarantees were executed later in the process.

TABLE 11

Individual Grades for Issues Within the Catagories for the Contracts Evaluated

Category and Issues Graded	Supplier and Contract Number						
	Calpine 11	Calpine 12	Calpine 13	Dynegy 6	Dynegy 7	Dynegy 14	Dynegy 15
A. Reliability of Performance — Delivery							
Is seller's failure to deliver an event of default? (–1, 0, 1)	-1	-1	-1	-1	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	-1	-1	-1	-1	-1	-1	-1
Seller's contractual incentives to perform (–1, 0, 1)	-1	-1	-1	0	0	0	0
Seller's price incentives to perform (–1, 0, 1)	1	1	1	1	1	1	1
Department's ability to manage risk of nonperformance (0, 1)	0	0	0	0	0	0	0
Seller's outs (–1, 0, 1)	-1	-1	-1	0	0	0	0
Overall Grade — Delivery	**-3**	**-3**	**-3**	**-1**	**-1**	**-1**	**-1**
B. Reliability of Performance — Availability							
Is seller's failure to perform an event of default? (–1, 0, 1)	-1	-1	N/A	-1	-1	N/A	N/A
Penalties for seller's nonperformance (–1, 0, 1)	-1	-1	N/A	-1	-1	N/A	N/A
Seller's contractual incentives to perform (–1, 0, 1)	-1	-1	N/A	-1	-1	N/A	N/A
Seller's price incentives to perform (–1, 0, 1)	1	1	N/A	1	1	N/A	N/A
Department's ability to manage risk of nonperformance (0, 1)	0	0	N/A	0	0	N/A	N/A
Seller's outs (–1, 0, 1)	-1	-1	N/A	0	0	N/A	N/A
Overall Grade — Availability	**-3**	**-3**	**0**	**-2**	**-2**	**0**	**0**
C. Reliability of Performance — Building New Generation							
Is seller's failure to perform an event of default? (–1, 0, 1)	-1	-1	N/A	N/A	N/A	N/A	N/A
Penalties for seller's nonperformance (–1, 0, 1)	-1	-1	N/A	N/A	N/A	N/A	N/A
Seller's contractual incentives to perform (–1, 0, 1)	-1	-1	N/A	N/A	N/A	N/A	N/A
Seller's price incentives to perform (–1, 0, 1)	1	1	N/A	N/A	N/A	N/A	N/A
Department's ability to manage risk of non-performance (0, 1)	0	0	N/A	N/A	N/A	N/A	N/A
Seller's outs (–1, 0, 1)	-1	-1	N/A	N/A	N/A	N/A	N/A
Overall Grade — New Generation	**-3**	**-3**	**0**	**0**	**0**	**0**	**0**
D. Price Risk — Uncertainty of Price							
Seller's pass-throughs (–1, 0, 1)	-1	-1	-1	-1	-1	-1	-1
Department credits (0, 1)	0	0	0	0	0	0	0
Allocation of environmental risk (–1, 0)	0	0	0	-1	-1	-1	-1
Overall Grade — Price Uncertainty	**-1**	**-1**	**-1**	**-2**	**-2**	**-2**	**-2**
E. Price Risk — Tolling Agreement							
Department's exposure to fuel price risk (–1, 0, 1)	N/A	N/A	N/A	-1	-1	-1	-1
Department's exposure to operating inefficiency risk (–1, 0, 1)	N/A	N/A	N/A	0	0	0	0
Overall Grade — Tolling Terms	**0**	**0**	**0**	**-1**	**-1**	**-1**	**-1**
FLEXIBILITY TO RENEGOTIATE OR QUIT							
A. Constraints on Department's Ability Not to Perform							
Outs for department (–1, 0, 1)	-1	-1	-1	-1	-1	-1	-1
Dispatchable vs. take or pay (1, –1)	-1	1	1	-1	-1	-1	-1
Limits of State's liability (–1, 0, 1)	0	-1	-1	0	0	0	0
Overall Grade — Department's Constraints to Renegotiate	**-2**	**-1**	**-1**	**-2**	**-2**	**-2**	**-2**
B. Department's Ability to Obtain Relief Through Governmental Action							
Recoup expenditures through taxes (0,1)	0	0	0	0	0	0	0
Obtain relief from FERC (0, 1)	0	0	0	0	0	0	0
Overall Grade — Other Means of Relief	**0**	**0**	**0**	**0**	**0**	**0**	**0**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM							
Ability to assign/delegate to government entities (–1, 0, 1)	0	0	0	1	1	1	1
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	-1	-1	-1	1	1	1	1
Overall Grade — Assignment	**-1**	**-1**	**-1**	**2**	**2**	**2**	**2**

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Shaded contracts were reviewed in detail by our consultant.

Category and Issues Graded	Supplier and Contract Number					
	Dynegy 16	Dynegy 17	Williams 8	Williams 9	Williams 10	Williams 18
A. Reliability of Performance — Delivery						
Is seller's failure to deliver an event of default? (–1, 0, 1)	-1	-1	-1	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	-1	-1	-1	-1	-1	-1
Seller's contractual incentives to perform (–1, 0, 1)	0	0	0	0	0	0
Seller's price incentives to perform (–1, 0, 1)	1	1	1	1	1	1
Department's ability to manage risk of nonperformance (0, 1)	0	0	0	0	0	0
Seller's outs (–1, 0, 1)	0	0	-1	-1	-1	-1
Overall Grade — Delivery	**-1**	**-1**	**-2**	**-2**	**-2**	**-2**
B. Reliability of Performance — Availability						
Is seller's failure to perform an event of default? (–1, 0, 1)	-1	-1	-1	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	-1	-1	1	1	1	1
Seller's contractual incentives to perform (–1, 0, 1)	-1	-1	1	1	1	1
Seller's price incentives to perform (–1, 0, 1)	1	1	1	1	1	1
Department's ability to manage risk of nonperformance (0, 1)	0	0	0	0	0	0
Seller's outs (–1, 0, 1)	0	0	-1	-1	-1	-1
Overall Grade — Availability	**-2**	**-2**	**1**	**1**	**1**	**1**
C. Reliability of Performance — Building New Generation						
Is seller's failure to perform an event of default? (–1, 0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Penalties for seller's nonperformance (–1, 0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Seller's contractual incentives to perform (–1, 0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Seller's price incentives to perform (–1, 0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Department's ability to manage risk of non-performance (0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Seller's outs (–1, 0, 1)	N/A	N/A	N/A	N/A	N/A	N/A
Overall Grade — New Generation	**0**	**0**	**0**	**0**	**0**	**0**
D. Price Risk — Uncertainty of Price						
Seller's pass-throughs (–1, 0, 1)	-1	-1	-1	-1	-1	-1
Department credits (0, 1)	0	0	0	0	0	0
Allocation of environmental risk (–1, 0)	-1	-1	-1	-1	-1	-1
Overall Grade — Price Uncertainty	**-2**	**-2**	**-2**	**-2**	**-2**	**-2**
E. Price Risk — Tolling Agreement						
Department's exposure to fuel price risk (–1, 0, 1)	-1	-1	N/A	N/A	N/A	N/A
Department's exposure to operating inefficiency risk (–1, 0, 1)	0	0	N/A	N/A	N/A	N/A
Overall Grade — Tolling Terms	**-1**	**-1**	**0**	**0**	**0**	**0**
FLEXIBILITY TO RENEGOTIATE OR QUIT						
A. Constraints on Department's Ability Not to Perform						
Outs for department (–1, 0, 1)	-1	-1	-1	-1	-1	-1
Dispatchable vs. take or pay (1, –1)	-1	-1	-1	-1	-1	-1
Limits of State's liability (–1, 0, 1)	0	0	-1	-1	-1	-1
Overall Grade — Department's Constraints to Renegotiate	**-2**	**-2**	**-3**	**-3**	**-3**	**-3**
B. Department's Ability to Obtain Relief Through Governmental Action						
Recoup expenditures through taxes (0,1)	0	0	0	0	0	0
Obtain relief from FERC (0, 1)	0	0	0	0	0	0
Overall Grade — Other Means of Relief	**0**	**0**	**0**	**0**	**0**	**0**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM						
Ability to assign/delegate to government entities (–1, 0, 1)	1	1	1	1	1	1
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	1	1	-1	-1	-1	-1
Overall Grade — Assignment	**2**	**2**	**0**	**0**	**0**	**0**

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Category and Issues Graded	Supplier and Contract Number					
	Allegheny 21	Allegheny 22	Allegheny 27	Constellation 20	Cal Peak 43	Cal Peak 44
A. Reliability of Performance — Delivery						
Is seller's failure to deliver an event of default? (–1, 0, 1)	-1	-1	-1	-1	0	0
Penalties for seller's nonperformance (–1, 0, 1)	0	0	0	0	0	0
Seller's contractual incentives to perform (–1, 0, 1)	0	0	0	0	1	1
Seller's price incentives to perform (–1, 0, 1)	0	0	0	0	0	0
Department's ability to manage risk of nonperformance (0, 1)	0	0	0	0	0	0
Seller's outs (–1, 0, 1)	0	0	0	0	1	1
Overall Grade — Delivery	**-1**	**-1**	**-1**	**-1**	**2**	**2**
B. Reliability of Performance — Availability						
Is seller's failure to perform an event of default? (–1, 0, 1)	-1	-1	N/A	N/A	0	0
Penalties for seller's nonperformance (–1, 0, 1)	0	0	N/A	N/A	0	0
Seller's contractual incentives to perform (–1, 0, 1)	0	0	N/A	N/A	1	1
Seller's price incentives to perform (–1, 0, 1)	0	0	N/A	N/A	0	0
Department's ability to manage risk of nonperformance (0, 1)	0	0	N/A	N/A	1	1
Seller's outs (–1, 0, 1)	0	0	N/A	N/A	1	1
Overall Grade — Availability	**-1**	**-1**	**0**	**0**	**3**	**3**
C. Reliability of Performance — Building New Generation						
Is seller's failure to perform an event of default? (–1, 0, 1)	N/A	N/A	N/A	N/A	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	N/A	N/A	N/A	N/A	1	1
Seller's contractual incentives to perform (–1, 0, 1)	N/A	N/A	N/A	N/A	0	0
Seller's price incentives to perform (–1, 0, 1)	N/A	N/A	N/A	N/A	0	0
Department's ability to manage risk of non-performance (0, 1)	N/A	N/A	N/A	N/A	1	1
Seller's outs (–1, 0, 1)	N/A	N/A	N/A	N/A	1	1
Overall Grade — New Generation	**0**	**0**	**0**	**0**	**2**	**2**
D. Price Risk — Uncertainty of Price						
Seller's pass-throughs (–1, 0, 1)	0	0	0	0	0	0
Department credits (0, 1)	1	1	1	1	0	0
Allocation of environmental risk (–1, 0)	0	0	0	0	0	0
Overall Grade — Price Uncertainty	**1**	**1**	**1**	**1**	**0**	**0**
E. Price Risk — Tolling Agreement						
Department's exposure to fuel price risk (–1, 0, 1)	N/A	N/A	N/A	N/A	1	1
Department's exposure to operating inefficiency risk (–1, 0, 1)	N/A	N/A	N/A	N/A	1	1
Overall Grade — Tolling Terms	**0**	**0**	**0**	**0**	**2**	**2**
FLEXIBILITY TO RENEGOTIATE OR QUIT						
A. Constraints on Department's Ability Not to Perform						
Outs for department (–1, 0, 1)	-1	-1	-1	-1	1	1
Dispatchable vs. take or pay (1, –1)	-1	-1	-1	-1	1	1
Limits of State's liability (–1, 0, 1)	0	0	0	0	0	0
Overall Grade — Department's Constraints to Renegotiate	**-2**	**-2**	**-2**	**-2**	**2**	**2**
B. Department's Ability to Obtain Relief Through Governmental Action						
Recoup expenditures through taxes (0,1)	0	0	0	1	1	1
Obtain relief from FERC (0, 1)	0	0	0	1	0	0
Overall Grade — Other Means of Relief	**0**	**0**	**0**	**2**	**1**	**1**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM						
Ability to assign/delegate to government entities (–1, 0, 1)	1	1	1	1	1	1
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	1	1	1	1	-1	-1
Overall Grade — Assignment	**2**	**2**	**2**	**2**	**0**	**0**

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Category and Issues Graded	Supplier and Contract Number				
	Cal Peak 45	Cal Peak 46	High Desert 19	Sempra 28	Sempra 29
A. Reliability of Performance — Delivery					
Is seller's failure to deliver an event of default? (–1, 0, 1)	0	0	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	0	0	-1	0	0
Seller's contractual incentives to perform (–1, 0, 1)	1	1	0	0	0
Seller's price incentives to perform (–1, 0, 1)	0	0	1	0	0
Department's ability to manage risk of nonperformance (0, 1)	0	0	0	0	0
Seller's outs (–1, 0, 1)	1	1	-1	-1	-1
Overall Grade — Delivery	**2**	**2**	**-2**	**-2**	**-2**
B. Reliability of Performance — Availability					
Is seller's failure to perform an event of default? (–1, 0, 1)	0	0	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	0	0	-1	0	0
Seller's contractual incentives to perform (–1, 0, 1)	1	1	0	0	0
Seller's price incentives to perform (–1, 0, 1)	0	0	0	0	0
Department's ability to manage risk of nonperformance (0, 1)	1	1	0	0	0
Seller's outs (–1, 0, 1)	1	1	-1	-1	-1
Overall Grade — Availability	**3**	**3**	**-3**	**-2**	**-2**
C. Reliability of Performance — Building New Generation					
Is seller's failure to perform an event of default? (–1, 0, 1)	-1	-1	1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	1	1	1	-1	-1
Seller's contractual incentives to perform (–1, 0, 1)	0	0	0	0	0
Seller's price incentives to perform (–1, 0, 1)	0	0	0	0	0
Department's ability to manage risk of non-performance (0, 1)	1	1	1	0	0
Seller's outs (–1, 0, 1)	1	1	-1	-1	-1
Overall Grade — New Generation	**2**	**2**	**2**	**-3**	**-3**
D. Price Risk — Uncertainty of Price					
Seller's pass-throughs (–1, 0, 1)	0	0	1	0	0
Department credits (0, 1)	0	0	0	0	0
Allocation of environmental risk (–1, 0)	0	0	0	0	0
Overall Grade — Price Uncertainty	**0**	**0**	**1**	**0**	**0**
E. Price Risk — Tolling Agreement					
Department's exposure to fuel price risk (–1, 0, 1)	1	1	N/A	1	1
Department's exposure to operating inefficiency risk (–1, 0, 1)	1	1	N/A	0	0
Overall Grade — Tolling Terms	**2**	**2**	**0**	**1**	**1**
FLEXIBILITY TO RENEGOTIATE OR QUIT					
A. Constraints on Department's Ability Not to Perform					
Outs for department (–1, 0, 1)	1	1	-1	0	0
Dispatchable vs. take or pay (1, –1)	1	1	-1	-1	-1
Limits of State's liability (–1, 0, 1)	0	0	0	0	0
Overall Grade — Department's Constraints to Renegotiate	**2**	**2**	**-2**	**-1**	**-1**
B. Department's Ability to Obtain Relief Through Governmental Action					
Recoup expenditures through taxes (0,1)	1	1	1	0	0
Obtain relief from FERC (0, 1)	0	0	1	0	0
Overall Grade — Other Means of Relief	**1**	**1**	**2**	**0**	**0**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM					
Ability to assign/delegate to government entities (–1, 0, 1)	1	1	0	1	1
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	-1	-1	0	1	1
Overall Grade — Assignment	**0**	**0**	**0**	**2**	**2**

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Category and Issues Graded	Supplier and Contract Number				
	Pacificorp 40	Sunrise 41	Sunrise 42	GWF 31	Mirant 32
A. Reliability of Performance — Delivery					
Is seller's failure to deliver an event of default? (–1, 0, 1)	1	1	1	0	-1
Penalties for seller's nonperformance (–1, 0, 1)	1	-1	-1	1	-1
Seller's contractual incentives to perform (–1, 0, 1)	0	1	1	1	0
Seller's price incentives to perform (–1, 0, 1)	0	1	1	1	0
Department's ability to manage risk of nonperformance (0, 1)	0	1	1	1	0
Seller's outs (–1, 0, 1)	1	0	0	-1	-1
Overall Grade — Delivery	**3**	**3**	**3**	**3**	**-3**
B. Reliability of Performance — Availability					
Is seller's failure to perform an event of default? (–1, 0, 1)	1	-1	-1	0	N/A
Penalties for seller's nonperformance (–1, 0, 1)	0	0	0	1	N/A
Seller's contractual incentives to perform (–1, 0, 1)	0	1	1	1	N/A
Seller's price incentives to perform (–1, 0, 1)	0	1	1	1	N/A
Department's ability to manage risk of nonperformance (0, 1)	1	1	1	1	N/A
Seller's outs (–1, 0, 1)	1	0	0	-1	N/A
Overall Grade — Availability	**3**	**2**	**2**	**3**	**0**
C. Reliability of Performance — Building New Generation					
Is seller's failure to perform an event of default? (–1, 0, 1)	N/A	-1	-1	0	N/A
Penalties for seller's nonperformance (–1, 0, 1)	N/A	1	1	0	N/A
Seller's contractual incentives to perform (–1, 0, 1)	N/A	1	1	0	N/A
Seller's price incentives to perform (–1, 0, 1)	N/A	-1	-1	1	N/A
Department's ability to manage risk of non-performance (0, 1)	N/A	1	1	1	N/A
Seller's outs (–1, 0, 1)	N/A	0	0	-1	N/A
Overall Grade — New Generation	**0**	**1**	**1**	**1**	**0**
D. Price Risk — Uncertainty of Price					
Seller's pass-throughs (–1, 0, 1)	0	0	0	-1	0
Department credits (0, 1)	0	0	0	0	1
Allocation of environmental risk (–1, 0)	0	0	0	-1	0
Overall Grade — Price Uncertainty	**0**	**0**	**0**	**-2**	**1**
E. Price Risk — Tolling Agreement					
Department's exposure to fuel price risk (–1, 0, 1)	1	1	1	1	N/A
Department's exposure to operating inefficiency risk (–1, 0, 1)	0	0	0	1	N/A
Overall Grade — Tolling Terms	**1**	**1**	**1**	**2**	**0**
FLEXIBILITY TO RENEGOTIATE OR QUIT					
A. Constraints on Department's Ability Not to Perform					
Outs for department (–1, 0, 1)	0	1	1	1	0
Dispatchable vs. take or pay (1, –1)	1	-1	-1	1	-1
Limits of State's liability (–1, 0, 1)	0	0	0	0	0
Overall Grade — Department's Constraints to Renegotiate	**1**	**0**	**0**	**2**	**-1**
B. Department's Ability to Obtain Relief Through Governmental Action					
Recoup expenditures through taxes (0,1)	0	1	1	0	0
Obtain relief from FERC (0, 1)	1	1	1	0	0
Overall Grade — Other Means of Relief	**1**	**2**	**2**	**0**	**0**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM					
Ability to assign/delegate to government entities (–1, 0, 1)	1	1	1	1	0
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	1	-1	-1	-1	0
Overall Grade — Assignment	**2**	**0**	**0**	**0**	**0**

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Category and Issues Graded	Supplier and Contract Number				
	Coral 33	Coral 34	Coral 35	Coral 36	CalpineSJ 49
A. Reliability of Performance — Delivery					
Is seller's failure to deliver an event of default? (–1, 0, 1)	-1	-1	-1	-1	-1
Penalties for seller's nonperformance (–1, 0, 1)	0	0	0	0	0
Seller's contractual incentives to perform (–1, 0, 1)	0	0	0	0	1
Seller's price incentives to perform (–1, 0, 1)	1	1	1	1	1
Department's ability to manage risk of nonperformance (0, 1)	1	1	1	1	1
Seller's outs (–1, 0, 1)	0	0	0	0	-1
Overall Grade — Delivery	**1**	**1**	**1**	**1**	**1**
B. Reliability of Performance — Availability					
Is seller's failure to perform an event of default? (–1, 0, 1)	0	0	0	0	-1
Penalties for seller's nonperformance (–1, 0, 1)	1	1	1	1	0
Seller's contractual incentives to perform (–1, 0, 1)	1	1	1	1	1
Seller's price incentives to perform (–1, 0, 1)	0	0	0	0	1
Department's ability to manage risk of nonperformance (0, 1)	1	1	1	1	1
Seller's outs (–1, 0, 1)	1	1	1	1	0
Overall Grade — Availability	**4**	**4**	**4**	**4**	**2**
C. Reliability of Performance — Building New Generation					
Is seller's failure to perform an event of default? (–1, 0, 1)	0	0	0	0	0
Penalties for seller's nonperformance (–1, 0, 1)	1	1	1	1	-1
Seller's contractual incentives to perform (–1, 0, 1)	0	0	0	0	0
Seller's price incentives to perform (–1, 0, 1)	1	1	1	1	1
Department's ability to manage risk of non-performance (0, 1)	1	1	1	1	0
Seller's outs (–1, 0, 1)	0	0	0	0	0
Overall Grade — New Generation	**3**	**3**	**3**	**3**	**0**
D. Price Risk — Uncertainty of Price					
Seller's pass-throughs (–1, 0, 1)	0	0	0	0	0
Department credits (0, 1)	1	1	1	1	1
Allocation of environmental risk (–1, 0)	0	0	0	0	0
Overall Grade — Price Uncertainty	**1**	**1**	**1**	**1**	**1**
E. Price Risk — Tolling Agreement					
Department's exposure to fuel price risk (–1, 0, 1)	1	1	1	1	0
Department's exposure to operating inefficiency risk (–1, 0, 1)	0	0	0	0	1
Overall Grade — Tolling Terms	**1**	**1**	**1**	**1**	**1**
FLEXIBILITY TO RENEGOTIATE OR QUIT					
A. Constraints on Department's Ability Not to Perform					
Outs for department (–1, 0, 1)	1	1	1	1	1
Dispatchable vs. take or pay (1, –1)	1	1	1	1	1
Limits of State's liability (–1, 0, 1)	0	0	0	0	0
Overall Grade — Department's Constraints to Renegotiate	**2**	**2**	**2**	**2**	**2**
B. Department's Ability to Obtain Relief Through Governmental Action					
Recoup expenditures through taxes (0,1)	0	0	0	0	0
Obtain relief from FERC (0, 1)	0	0	0	0	0
Overall Grade — Other Means of Relief	**0**	**0**	**0**	**0**	**0**
ABILITY TO ASSIGN/DELEGATE IF DEPARTMENT EXITS THE PROGRAM					
Ability to assign/delegate to government entities (–1, 0, 1)	1	1	1	1	0
Ability to assign/delegate to nongovernment entities (–1, 0, 1)	-1	-1	-1	-1	-1
Overall Grade — Assignment	**0**	**0**	**0**	**0**	**-1**

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APPENDIX D

Structure of the California Electricity Market

KEY FEATURES AND PARTICIPANTS

The California Independent System Operator (ISO) is a state-chartered nonprofit corporation that operates the transmission systems of the participating transmission owners. The ISO operates the Open Access Same Time Information System, which provides market participants with important information about available transmission capacity. In addition, the ISO coordinates transmission scheduling and congestion management, procures ancillary services as needed to ensure reliability of the electricity system, and performs billings and collections for these services.

The ISO administers the scheduling of day-ahead, hour-ahead transactions, and real-time markets for energy and generation-based ancillary services. It requires buyers and sellers to schedule power deliveries or to provide ancillary services and supplemental energy bids through scheduling coordinators (SCs). SCs serve as intermediaries in the California market, coordinating the flow of information between the ISO and the market participants. Through the day-ahead and hour-ahead scheduling activities, the SCs must submit balanced schedules to the ISO. SCs relay all operating instructions from the ISO to the market participants. Under the original design of the California electricity market, the California Power Exchange (power exchange) functioned as the SC for all generation and load associated with investor-owned utilities in California. Since the bankruptcy of the power exchange in early 2001, each investor-owned utility has functioned as the SC for its load and generation, including the portion that the Department of Water Resources procures on its behalf.

Note that the ISO does not operate a power exchange—that is, a platform through which parties can trade energy and related services—and does not perform a centralized dispatch of the power plants in California. Market participants in California negotiate the terms (including amounts, delivery locations, and prices) of their transactions, develop the schedules of power plant generation to serve those transactions, and report the results to the ISO in the form of balanced schedules.

OPERATION OF THE CALIFORNIA ELECTRICITY MARKET

The ISO administers markets in three time horizons: day-ahead, hour-ahead, and real time. SCs are required to submit balanced schedules—that is, schedules in which aggregate hourly amounts of generation and demand are equal—to the ISO in the day-ahead and hour-ahead markets.

Day-Ahead Market

The day-ahead market is used to establish the expected operation of the electricity system for the next day. It is the forward market for energy and ancillary services administered by the ISO through which energy or ancillary services are scheduled for delivery during each hour of the next trading day (24-hour trading period).

Scheduling in the day-ahead market occurs as follows:

1. The ISO provides the SCs with information regarding the status of the system, such as transmission line outages, a forecast of zonal demand, control area ancillary services requirements, and expected congestion conditions, to aid the SCs in developing their day-ahead schedules.

2. The SCs provide the ISO with a demand forecast and the ISO publishes an updated forecast of system demand and ancillary services requirements.

3. Firm transmission rights and existing transmission contracts are defined and the remaining firm transmission rights are made available by auction.

4. The SCs submit their day-ahead schedules and ancillary services bids and schedules.

5. The ISO provides all SCs with suggested adjusted day-ahead schedules for energy, estimated day-ahead usage charges for energy transfers between zones, and schedules for ancillary services, including suggestions for modifying the schedules in order to relieve congestion at the least cost.

6. The SCs reschedule the amounts and delivery points of transactions and generation to reduce congestion in response to the ISO's suggested adjusted schedules by submitting a revised day-ahead schedule.

7. The ISO issues final day-ahead schedules and an updated forecast of system demand.

Hour-Ahead Market

The hour-ahead market is designed to allow SCs to make adjustments to the day-ahead schedules during the trading day in response to differences between the day-ahead forecast demand and scheduled generation and updated demand forecasts. This is the forward market for energy and ancillary services conducted by the ISO through which energy or ancillary services are scheduled each hour for delivery during a trading day. Actual market operation will differ slightly from the day-ahead market commitments, so the ISO calculates the difference between the final hour-ahead schedules and the final day-ahead schedules, and all differences are settled in the hour-ahead market. This is the last opportunity for SCs to submit their preferred hour-ahead schedules, contract and firm transmission rights, and ancillary service bids to the ISO. The ISO uses each SC's preferred hour-ahead schedule unless it fails validation—that is, unless it cannot be accommodated due to congestion management. In that case, the ISO uses the SC's final day-ahead schedule.

Real-Time Market

The real-time market is the competitive generation market operated and administered by the ISO for the provision of real-time imbalance energy. The ISO needs to purchase or sell imbalance energy when actual electricity demand and generation turns out differently from the hour-ahead schedules. Imbalance energy is supplied from generators providing regulation, spinning and nonspinning reserves, replacement reserves, and from other generating units, resources, or loads that are able to respond to the ISO's requests for more or less energy in real time to instantly balance the system and relieve intrazonal congestion.

In this market, the ISO uses its system dispatch software, as well as generator bids for ancillary services and supplemental energy, to match real-time operational fluctuations in load and generation. The ISO selects the least-cost set of resources to supply these services. In general, resources bid into the real-time market are dispatched in merit order. The clearing price is established by the highest accepted bid; at present, there is a per megawatt-hour price cap imposed by the Federal Energy Regulatory Commission (FERC) on clearing prices in the real-time imbalance market.

Out-of-Market Purchases

In the event that inadequate supply has been bid into the real-time market, the ISO is authorized to make out-of-market (OOM) bilateral purchases and sales in order to balance the market and ensure grid security. There is no FERC price cap on OOM transactions.

Agency's comments provided as text only.

Resources Agency
1416 Ninth Street, Suite 1311
Sacramento, CA 95814

To: Elaine M. Howle, State Auditor*
Bureau of State Audits
555 Capitol Mall, Suite 300
Sacramento, California 95814

From: Mary Nichols *(Signed by: Michael Sweeney, Undersecretary, for Mary Nichols)*
Secretary for Resources

SUBJECT: Department of Water Resources' Comments to the Bureau of State Audit's Draft Report

Enclosed are the Department of Water Resources' comments on the Bureau of State Audits draft report entitled "California Energy Markets: Pressures Have Eased, but Cost Risks Remain," December 2001. The report is focused on DWR's implementation of Assembly Bill 1X.

These comments are in response to the version of the report provided to me on November 30, 2001 and revised additional text provided on December 7 and 8, 2001. We have not had the opportunity to comment on any modifications made after that date.

If your staff wish to discuss DWR's comments, please contact Peter Garris, Acting Deputy Director of the California Energy Resources Scheduling Division, Department of Water Resources at (916) 574-2733.

Enclosure

*California State Auditor's comments begin on page 247.

To: Honorable Mary D. Nichols
Secretary for Resources
The Resources Agency
1416 Ninth Street, Room 1311
Sacramento, California 95814

From: Department of Water Resources

Subject: Department of Water Resources' Response to the State Auditor's Draft Report

This memo summarizes the Department of Water Resources' principal concerns with the Bureau of State Audit's draft report "California Energy Markets: Pressures Have Eased, but Cost Risks Remain," December 2001. Attached to this memo are DWR's more detailed comments on the Auditor's report. The Auditor's report assesses the performance of DWR in implementing the statutory mandates of Division 27 that was added to the Water Code by the Legislature in AB 1X. AB 1X charged DWR with the responsibility of purchasing the net short energy requirements of the customers of the State's financially insolvent investor-owned electric utilities in California.

Division 27 to the Water Code set forth in clear and unambiguous terms the state's urgent need for *"reliable and reasonably price energy"*. It was the Legislature's direction to DWR to respond *"adequately and expeditiously"* in undertaking and administering this critical responsibility. The urgency of the Legislature's directive was in response to their finding that the State had suffered a *"rapid, unforeseen shortage of electric power and energy" and "substantial increases in wholesale energy costs and retail energy rates"*, and that failing to respond both *"adequately and expeditiously"* would mean *"immediate peril to the health, safety, life and property of the inhabitants of the state"*.

(1) **The Report Does Not Address the Impact of DWR's Decisions on the Market and Uses the Wrong Standard of Evaluation**

It is inevitable, given the benefit of hindsight and additional information, that DWR would want to revisit and revise certain decisions. However, as a matter of both fairness and accuracy, I believe that the Bureau's report fails in its primary purpose. The Report does not assess the success of DWR's decisions in stabilizing prices and restoring system reliability, nor does it evaluate the reasonableness of DWR's decisions within the context of the crisis environment that they were made, the information that was available to DWR at the time, and against the tremendous risks to the State's economy, and health and safety of its citizens in failing to take decisive action. With this balanced view in mind, DWR offers its comments.

DWR embarked on its power purchase program with the following critical objectives:

➢ **Establish DWR as a creditworthy party quickly by signing long-term contracts.** Establishing DWR as a creditworthy market participant was critical to the success of DWR's power purchase program; *first,* it was necessary to convince enough power sellers to sign agreements to assure the timely acquisition of generation for the summers of 2001 and 2002; *second,* it had a direct impact on reducing the risk premium being charged by generators and marketers; *third*, it was essential to making short-term vendors comfortable with selling to DWR in the spot market; and *fourth*, it was necessary for convincing bond rating agencies that DWR was worthy of an "investment-grade" rating.

Establishing a creditworthy presence in the view of other market participants was especially important to restoring reliability. At the onset of DWR's power purchasing activities, credit concerns were often the stated cause of sellers' unwillingness to sell to California and DWR.

Of course, having investment grade bonds is the linchpin to repaying the State's General Fund over $6 billion that has been spent on short-term energy purchases. AB 1X specifically prohibits the State from issuing debt without an investment-grade rating.

➢ **Utilize industry standard contracts containing accepted and recognized terms and conditions that would ensure contractor performance.** Use of accepted form contracts was critical for DWR to achieve the market stabilization mandates of AB 1X in the necessary time frame. These contracts provide DWR with commercially reasonable assurances it will receive the power it bargained for at the agreed-upon prices. If the generators fail to deliver power for which they are obligated, the contracts would provide for payment to DWR of substantial financial damages.

➢ **Secure enough power supply under long-term contracts in quantities that would limit the state's exposure to volatile spot market prices.** DWR began its power purchasing activity spending between $60 million to $100 million per day. The average daily spot market price for energy was in excess of $400/MWh with hourly peak period prices ranging from $300 to over $1,000/MWh. DWR was consistently requesting $500 million from the General Fund with ten days advance notice—the limit established under AB 1X—to meet its cash flow requirements for the purchases. The daily drain on the General Fund had to be reduced if the State was to have the temporary cash it needed to meet the normal requirements of government, while still providing funds sufficient to maintain reliability of the electric grid.

The State's near-term exposure to volatile spot market prices was not DWR's only concern. Projections for the cost of spot market power for the summer peak hours of 2001 were in excess of $300/MWh. Several experts projected prices in excess of $400/MWh throughout the summer of 2001 and 2002. The sooner DWR could secure energy under long-term contracts, the less exposure there was to these volatile spot prices. This threat was real enough to prompt some utilities in the West to sign forward contracts for deliveries of power that were well in excess of the average contract price negotiated by DWR. For example, in a recent complaint filed with the Federal Energy Regulatory Commission (EL02-28), Nevada Power and Sierra Pacific are asking FERC to readjust their forward contracts with Enron for the third quarter of 2002. The price of these contracts ranged from $230/MWh to $290/MWh. DWR's contracts for the same period have an average cost of $124/MWh.

➢ **Contract with developers of new power plants to provide the revenue certainty they needed to secure financing.** Contracting with developers of new power plants was critical not only to ensuring their timely completion and availability for the coming summer and next, but to also increasing overall generation capacity reserve levels in the State which have been declining steadily for the last 10 years. Adequate reserve levels are needed for both reliability, and for limiting the ability of generator's and marketers to manipulate price thereby reducing price volatility.

Major Achievements of DWR in Implementing AB 1X

(2) DWR believes that history provides an objective and unbiased assessment of its achievements and that the Bureau has ignored the following facts in their assessment of DWR's power purchase program:

➢ **Spot market prices are now in the range of $25 to $60/MWh when the industry projected prices at five to ten times this level for this period.** For the peak demand periods this represents between an 800 to 1,000 percent decline from spot market prices DWR was seeing as late as May.

➢ **DWR's daily cost of electricity has declined by 600 percent from the first weeks in January and February.** DWR new spends between $10 and $15 million per day to cover the utility net short energy requirement compared to the $60 to $100 million per day spent earlier in the year. This amount includes the amount paid for contract purchases, spot market purchases, and the cost of capacity reserves.

➢ **Despite dire predictions that the summer of 2001 would be plagued by several hundred hours of blackouts, there were none.** The last rotating blackout in the State was on May 8. The Independent System Operator declared a Stage 2 emergency–operating reserves less than five percent–for only two days in July.

➢ **For the summer of 2001, 70 to 80 percent of the utility net short energy requirement was met through long-term and short-term bilateral contracts.** This was a complete reversal of DWR's position in February where DWR was buying over 80 percent of the utility net short energy requirements in the spot market. DWR's contracting effort provided both supply certainty and limited exposure to volatile spot market prices for this past summer.

➢ **Over 70 percent of the energy contracted for by DWR will come from new power plants.** DWR's long-term contracts allowed developers to secure financing to guarantee the construction of a significant amount of the new generation capacity in the State. These contracts will also provide almost 1,300 MW of new peaking generation capacity that is critical to meeting spikes in demand during hot weather and maintaining minimum reserve levels that are essential to the reliability of the grid. (3)

The above achievements were not even conceivable in the first half of this year. Yet, the Auditor's report dismisses them as irrelevant in their assessment of the performance of DWR. The graphs attached to this memo dramatically illustrate how successful DWR was in meeting its statutory mandate. (2)

DWR recognizes that other factors, outside of DWR's control, have helped to mitigate the crisis that the State faced, principal among them being the voluntary conservation efforts of all Californians. Others have suggested that the State also benefited this past summer from milder than normal temperature conditions, a claim that the California Energy Commission has refuted. The summer of 2001 was not, on balance, a mild summer. In addition, the FERC price cap order of June 19, 2001 is also cited as contributing toward stabilizing the market. This claim ignores the fact that weeks before the FERC order, DWR was already purchasing spot market power at a price that was significantly lower than the FERC price cap and that since the cap was established, prices have continued to trade 50 to 70 percent lower than the FERC price cap, significantly questioning the impact of the cap on prices.

Of course, DWR is grateful for any and all-ancillary contributions to bringing about lower electricity prices and greater supply certainty and reliability. Again, the charge to the Bureau, however, was to assess the success of DWR in achieving the mandate of AB 1X—stable prices and reliability—and the reasonableness of DWR's actions. There is no conceivable scenario in my mind where the low prices and system reliability that we are currently seeing could have occurred without the involvement of DWR.

Challenges Remain to be Addressed

Under no circumstances, however, should the State be lulled into a sense of complacency with respect for the potential for future price and supply disruptions. DWR will continue for the next year to be responsible as the creditworthy backer for real-time energy imbalance costs. Because of a recent FERC order, the ability of DWR to monitor the costs and risk of real-time energy purchases has been severely curtailed.

Until December 14, 2001, DWR will have purchased much of the real-time energy required to balance the grid and ensure reliability through competitive spot markets. To date, DWR purchased real-time energy at the request of the ISO. A November 20, 2001 FERC order now requires that all real-time energy needed to balance the grid must be procured through ISO's real-time imbalance energy market.

The ISO's real-time market has been unreliable, with generators ignoring dispatch instructions, and costly. Under FERC's price cap order, all generators bidding into the ISO real-time market can receive a single market-clearing price that is capped at the cost of what is typically the dirtiest, least efficient power plant in the entire market. Not surprisingly, generators have a tendency to bid their energy into the ISO real-time market at inflated prices. Since the FERC order was issued, the price of imbalance energy procured through the ISO real-time market has increased 100 percent over the cost DWR was paying through competitive spot markets outside of the ISO market.

Furthermore, California ratepayers are currently at risk for several hundreds of millions of dollars in penalties that have been accruing under an ISO-filed FERC tariff. This particular tariff requires scheduling coordinators with ISO to submit a schedule in the day ahead or hour ahead forward markets that is out-of-balance by no more than 5 percent. As an incentive to submit balanced schedules there is a penalty assessed to each scheduling coordinator that fails to meet the criteria. ISO is not currently invoicing or collecting this penalty from scheduling coordinators. For the California Energy Resources Scheduling division of DWR that is scheduling the long-term contracts and forward market spot purchase against the net short requirements of the IOU's this penalty creates a problem for our ability to control costs for the following reasons:

1. It doesn't allow much flexibility to take advantage of lower real time spot prices, since 95% of the load must to be scheduled in the day ahead or hour ahead forward markets.

2. It represents a charge, which DWR may be billed for if and when the ISO is ordered to collect the penalty by the FERC, for actions of IOUs in scheduling load, when DWR has absolutely no control over IOUs' actions.

(4) The Report does not acknowledge this important flaw in the existing market system and FERC tariffs.

Audit Recommendations Reflect Actions Already Taken By DWR

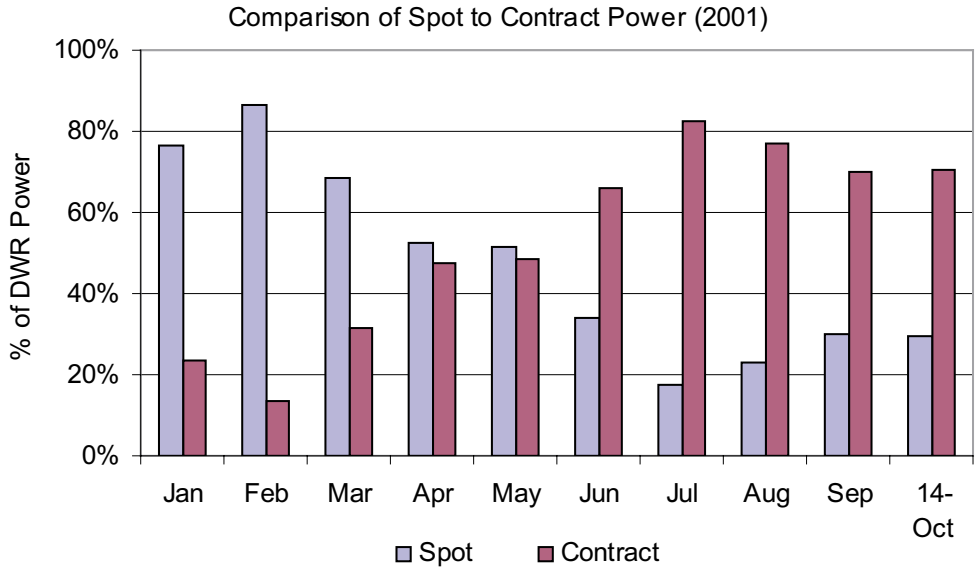
Lastly, I wish to also point out that DWR has already moved forward on implementing many of the recommendations in the Auditor's Report. The actions being taken by DWR were contemplated well before the Auditor's report and included in DWR's original business plan. These actions are described in the enclosed, more detailed review of the Report. 5

In summary I would just like to add how extremely proud I am of what DWR has accomplished given the magnitude of the task and the limited time and resources at it's disposal. The recent fate of Enron should serve as an example that having unlimited resources at one's disposal does not always ensure success. While others may second guess the decisions made by DWR, I believe that our comments make a clear and compelling case that our decisions were not only reasonable, but were the best that could have been made at the time.

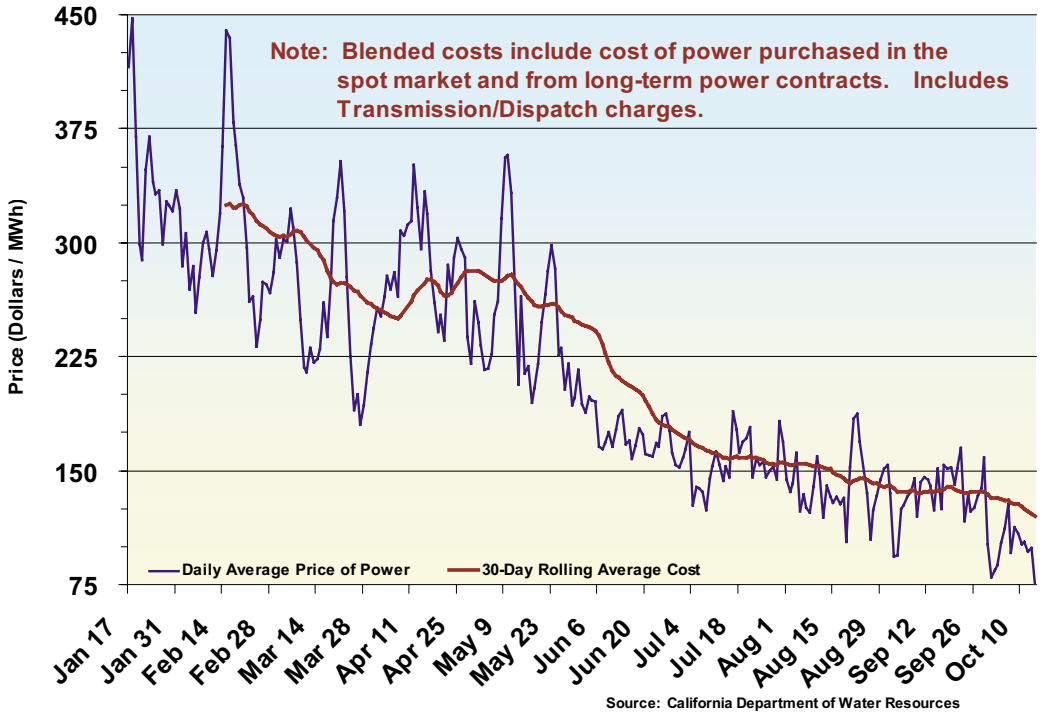
(Signed by: Thomas M. Hannigan)
Thomas M. Hannigan
Director
(916) 653-7007

Attachments

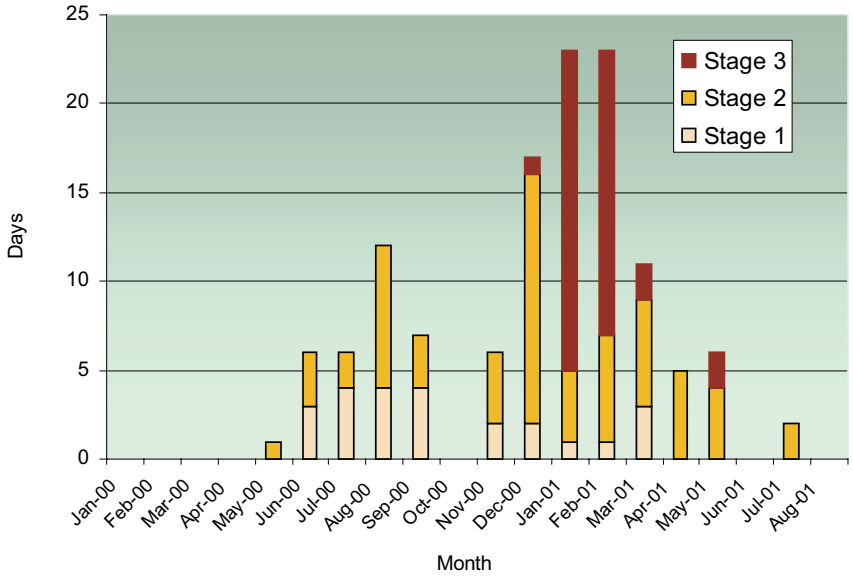
DWR Exposure In the Spot Market



Price of Power Provided by DWR Since January 17, 2001



ISO Staged Emergencies
(No Staged Emergencies since July 3rd)



Attachment

Detailed Comments of the Department of Water Resources on the Bureau of State Audit's Report on the Department's Power Purchase Program

December 10, 2001

OVERVIEW

Contained herein are the detailed comments of the California Department of Water Resources the California Bureau of State Audits draft report "California Energy Markets: Pressures Have Eased, but Cost Risks Remain," December, 2001 ("the Report"). While DWR had less than 2 weeks in which to review, respond and prepare these comments on the 280-page report, our comments on the findings and conclusions within the report are substantial. We provide these comments in the interest of clarifying to both the Bureau, and other parties reading the report, the role of DWR and the reasonableness of its actions and decisions. We also wish to inform the Bureau of the progress made by DWR toward implementing many of the recommendations noted in the report. In addition to providing a status report on the actions taken by DWR to improve its operations and management activities, we also provide here recommendations for policy and operational changes that need to be made by parties, other than DWR, that are critical to maintaining the reliability of the State's electricity system at the least possible cost.

(7) Before providing our specific comments on the Report, we wish to acknowledge the extraordinary task that the Bureau and its consultants faced in performing their analysis. It is clear that the authors of the Report have spent a substantial amount of time in evaluating the circumstances surrounding DWR's performance in implementing Assembly Bill 1X. The difficulty of this task was compounded by the Bureau's consultant's unfamiliarity with the dynamics and dysfunction of the deregulated market in California. Given this lack of experience and familiarity with the dynamics of a deregulated market on the part of the authors, it is understandable that they would mistakenly draw conclusions about the functioning of the California market based upon their experience in evaluating regulated electricity markets in other regions. Clearly, it is erroneous to draw parallels between the power supply decisions of a vertically integrated regulated utility which has a guaranteed rate of return on investment and an obligation to serve customers, to the supply decisions made by DWR in a dysfunctional market environment where merchant generators are pricing their product consistent with perceived, or manufactured, market risk, and have no obligation to serve customers.

(8) We also wish to point out that there is a significant disconnect between the more balanced and reasoned analysis contained within the text and the conclusions and the

chapter headings in the Report. The text of the Report recognizes the extraordinary circumstances surrounding the entrance of DWR into the market and the crisis environment in which decisions had to be made. This was not a time that allowed DWR to indulge in contemplative deliberation. The Report's analysis gives credence to the limitations that DWR was operating under, and what DWR could reasonably achieve given these limitations. The Report's chapter headings, and conclusions and recommendations, however, do not convey the balanced perspective in the text.

Key Concerns

Within the Report, DWR finds that the analytical approach used, certain observations, and key conclusions made to be fundamentally flawed based on (i) basic misunderstanding of DWR's role and mandate; (ii) a failure to appropriately acknowledge the circumstance beyond DWR's control that limited our ability to act more effectively; and (iii) misrepresentation of fact. These key concerns are as follows: (9)

1. The failure of Report to use an appropriate standard for evaluating the success of DWR's actions and the reasonableness of its decisions when the Legislature provided that standard in AB 1X.

2. The conclusion that DWR's supply portfolio does not provide a reliable supply when supply reliability has actually greatly increased.

3. The mischaracterization of DWR as the "energy provider of last resort" when the Independent System Operator has always legally held that responsibility.

4. The criticism of DWR for failing to adequately plan for new power plant development after 2002 , while at the same time criticizing DWR for entering into too many contracts for too much energy.

5. The criticism of DWR for not coordinating better with the California investor-owned utilities and ISO when those entities refused to fully cooperate with DWR.

The Legislature in AB 1X Provided Both the Standard for Evaluating DWR's Actions and the Conditions for Judging the Reasonableness of Its Decisions

One of the principal objections of DWR to the analysis within the Report is that the authors have failed to identify an appropriate standard for evaluating DWR's performance and success in implementing the objectives of AB 1X. The Report considers (10) the circumstances of the energy emergency almost as an afterthought. In fact, the primary purpose of AB 1X was, first, and foremost, to avert an unparalleled disaster to the State, to its economy, and to the health and safety of its citizens. By any measure, DWR's team, under the most daunting and unfavorable circumstances, succeeded in its primary mission of turning around a situation that posed the gravest threat to this State.

The Report never considers what would have happened if DWR had not succeeded in its primary mission. The consequences to the State of not succeeding provide the key to understanding the kinds of measures and the readiness with which DWR responded. In short, they are central to the evaluation of DWR's performance, which is, ostensibly, the purpose of this audit.

This audit was authorized by Water Code Section 80270 to assess the performance of DWR in implementing Division 27 of the Water Code, enacted by AB 1X to address the State's energy crisis. While the audit quite properly includes observations and recommendations of a general nature that can be helpful in future crises, it fails to
(11) use the appropriate standard for evaluating DWR's performance in carrying the statutory purposes of Division 27.

The purpose of Division 27 is set forth in its initial provisions. In Section 80000(a), the Legislature set forth in clear and explicit terms the State's urgent need for "reliable and reasonably priced energy" in a situation in which the State had suffered a *"rapid, unforeseen shortage of electric power and energy"* and *"substantial increases in wholesale energy costs and retail energy rates"*. It was, in the Legislature's continuing words, a situation of *"immediate peril to the health, safety, life and property of the inhabitants of the State"*. In Section 80000(b), the Legislature described the need for DWR to *"adequately and expeditiously undertake and administer the critical responsibilities established in this division"*.

In fact, the State was in the midst of an unprecedented crisis. California faced an incalculable energy shortage. There were daily emergency alerts from ISO; blackouts; approximately one-third of the State's generation capacity was off-line; and the cost of electricity and natural gas to generate electricity was skyrocketing. Wholesale electricity prices went from $15 to $30 per megawatt hour to between $300 and $1,000 per megawatt hour. In addition, the Federal Energy Regulatory Commission was unwilling to reign in wholesale electricity prices. The key market for transacting electricity, the California Power Exchange, was out of business. The two largest public utilities in the State (and nation), Pacific Gas & Electric and Southern California Edison, who provided retail electricity to two-thirds of the State, were financially insolvent and unable to buy electricity to serve their customers. When the Legislature passed AB 1X, the crisis had already prompted a Governor's Proclamation of a State of Emergency.

Disruptions in electrical energy service posed an ongoing threat to the health and safety of the citizens of the state. The State's economy—the 5th largest in the world—was in serious peril from blackouts and runaway energy prices. Furthermore, if the situation could not be turned around, the State of California, having to step in to buy electricity itself–at the rate of up to two billion dollars a month from the State's General Fund–was in jeopardy of financial ruin.

An objective evaluation of DWR success in meeting the goals set forth in Division of 27 of AB 1X must consider the crisis environment under which DWR was operating; the magnitude and unprecedented nature of the crisis; the relative limited staff

resources available to DWR, and the need to respond quickly. The auditor's evaluation should also have taken into account that before DWR could begin to act it had to create, from nothing, the basic institutional and logistical infrastructure needed to procure and schedule electricity on an daily, hourly, and real-time basis. The Report should have considered all of the above factors in its appraisal of DWR's performance. (12)

In addition to the *statutory purpose* and the *difficult circumstances* noted by the Legislature in AB 1X, the Report should have expressly recognized the *discretion* AB 1X understandably vested in DWR to choose a path for combating the crisis. Section 80100 sets forth not one but several broad criteria to guide DWR's purchase of electricity under AB1X, "on such terms and for such periods *as the department determines* and for such prices *as the department deems appropriate"*. The question for the auditor's appraisal of DWR's performance should not be, "Could something different have been done?" but rather, "Did DWR, given all the extenuating circumstances, act in a reasonable manner?" Again, Section 80100 sets forth several criteria that must, as a matter critical to both statutory interpretation and fairness, be understood as providing the relevant benchmark for measuring the success or failure of DWR's actions. (13)

DWR's Supply Portfolio Provides Reliable Supply

One of the major themes of the Report is that DWR's power contracts do not provide for reliable deliveries of energy in the future, in circumstances where the then-current spot market cost of energy is higher than the contract price. The Report states this theme as a factual conclusion repeatedly. DWR disagrees with this opinion. DWR respectfully suggests that the Bureau reconsider its conclusion on this point after considering more fully the provisions that are set forth in the contracts for liquidated damages, the purposes of the contracts and the circumstances in which they were negotiated. (14)

The power purchase agreements executed by DWR generally provide for the payment of liquidated or cover damages by the seller in the event that the seller fails to deliver energy pursuant to the agreement. The liquidated damages which are payable to DWR by the seller are equal to the difference between (i) the price DWR would have to pay to "replace" the energy which the seller was obligated to deliver; and (ii) the contract price which would have been payable by DWR had the seller actually delivered the energy.

For example, if a PPA provides for a $80 per MWh price, the seller fails to deliver, and DWR replaces the contracted-for energy with spot market purchases at $200 per MWh, the seller would be obligated to pay DWR $120 per MWh for the contracted-for amount of energy. As a result, the payment of LD's will permit DWR to receive the amount of energy contracted for at the contract price. In the event that the seller failed to pay the LD's that it owed to DWR, DWR could terminate the agreement, and the seller would be obligated to pay "termination liquidated damages".

Termination liquidated damages, which would be payable to DWR, are generally equal to the present value of the difference between the then-current market price for the contracted-for amount of energy and the contract price for the entire remaining term of the agreement, payable in a lump sum. Depending on the magnitude of a contract, termination liquidated damages could be hundreds of millions of dollars or more.

The basis for the report's conclusions concerning LD's (and reliability in general), appear to be based on the speculation that sellers will repeatedly elect to not deliver energy, and instead choose to pay liquidated damages. The presumed theory underlying the seller's behavior is that they will do this because they can potentially make more profit by selling the contracted-for energy (and additional energy the seller may control) in the spot market (even taking into account payment of the liquidated damages) than they would make by selling the energy to DWR. The Bureau's consultant argues that it may not be possible for DWR to replace energy at any price, and that therefore LD's do not provide sufficient incentive for a seller to meet its obligation to deliver energy, hence the Report's conclusion that such supply is not reliable within the meaning of AB 1X.

DWR believes that it is extremely unlikely that sellers would act in the manner contemplated by the Bureau's consultant, given the risks to the seller inherent in such a strategy. Stated simply, at the time that a seller elected not to deliver—and instead to take on the obligation to pay liquidated damages—it would not know what the department's replacement costs would be. Sellers are generally risk averse. If a seller elects to pay LDs, it would be at risk for, and have no control over, the cost of replacement energy as purchased by DWR. This risk to the seller would be greatest in situations where supply is scarce, in that the availability of spot market purchases for marginal amounts of energy is most unpredictable and the cost expensive. It is not reasonable for the Bureau to base its conclusions on a theory that sellers will act in a manner that entails risk of this magnitude. In fact, the theory is not consistent with the actual seller behavior.

During the initial critical months of California's crisis in which DWR's contracts were in place the contract price for energy was less than the then-current spot market price yet no sellers elected to pay liquidated damages, rather than deliver energy pursuant to their contract. Despite the fact that the consultant's basic theory is disproved by actual results, the theory remains as the backbone for a significant part of the Report, and is stated and restated as fact, rather than speculation.

The Report further suggests that DWR's contracts should have contained a right to terminate for non-delivery in order to assure reliable deliveries. If the greatest supply uncertainty, with respect to seller performance, occurs when the contract price is lower than the then the current market price, then termination of the agreement would benefit the seller. Presumably, the seller (freed from the contract) could make sales in the spot market at prices higher than the contract. This could theoretically be avoided by requiring the seller to pay the potentially massive termination liquidated damages described above. However, because of the magnitude of the termination liquidated damages, it is

unreasonable to conclude that sellers would generally agree to pay such termination damages unless they also retained the right to avoid termination by paying LD's.

During the contracting process, DWR consistently demanded that sellers provide contractual assurances that DWR would receive the contracted-for energy at the contracted-for price. LD's, coupled with the termination liquidated damages described above and the other provisions of the contract, achieves that goal.

DWR also notes that the scenario, which the Report claims represents a significant supply risk—spot market prices consistently exceeding the contract price—, would not occur anytime in the near future given the significant additions of new generation capacity in California and other western states.

The Department Was Never Given the Responsibility of Being the Energy Provider of Last Resort

Under AB 1X, DWR was solely authorized to purchase energy to cover the net short demand of the State's IOUs. (The net short demand is the IOU load not served by the IOU retained generation and contracts.) DWR was never given the legal responsibilities of the "provider of last resort" as the Report contends. Yet, the Report unfairly measures DWR contracts against those of a provider of last resort. (15)

That incorrect assessment leads to a near continuous criticism of DWR's contracting methods. First, the Report takes issue with the failure of DWR, as provider of last resort, to use an industry standard agreement. DWR considered many contracting options before it ultimately settled on the Edison Electric Institute Master Power Purchase Agreement. In spite of the Report's comments to the contrary, the EEI Agreement is the model contract widely used in the industry. It is applicable for long-term power sales of standard products. The agreement was developed over a two-year period resulting from a collaborative effort of utilities, generators, marketers, brokers, regulators, credit bankers, fuel suppliers, and others. (16)

Likewise, the Report criticizes DWR's decision to have "cover damages" (firm liquidated damages, or LDs) be the recourse against a seller's failure to deliver energy. The Report asserts that use of LDs was not suitable given DWR's role as the State's "energy provider of last resort". DWR always believed that ISO had the legal responsibilities of a provider of last resort. This view was upheld by FERC in their Nov. 20, 2001 Order. (14)

DWR has no Legal Obligation to Procure New Supplies Post 2002

In several instances, the Report criticizes DWR for not planning for the development of additional power plants beyond 2002. The Report specifically criticizes DWR for not providing for contracted power supplies through 2010, noting that the amount of power under contract after 2005 starts declining, leaving an increasing amount of power supply to the spot market or other sources which are uncertain. This criticism displays a total lack of understanding of DWR's responsibilities under AB 1X and is at
17 odds with the author's claim that DWR entered into too many contracts for too much energy, and that lower cost power would be available through the spot market.

Under AB 1X, DWR has no authority to enter into any contract for any purchase of any amount of energy for any purpose whatsoever after January 1, 2003 [Chapter 5, Termination of Authority to Contract]. DWR's role after 2002 is for the administration of existing contracts that were entered into prior to 2003. DWR's procurement of energy was solely as a transitional role until the IOUs are again creditworthy, the market is stabilized, and the IOUs or some other entity in a future restructuring of the California market assumes the purchase of net short energy.

As was noted in DWR's two requests for bids in January and February 2001, DWR preferred contracts for a term of three years or less. This preference was based on load and resource forecasts in early 2001 that indicated a return to surplus generation capacity reserve levels by 2003 or 2004. As long as there was reasonable financial assurance that power supplies would come on line to meet the 2003-2004 need, it was reasonable to assume that normal market forces and creditworthy utilities in the market would create a continued market for new power supply additions after 2004.

Unfortunately, suppliers were unwilling to offer power supply contracts that contained terms that offered both sufficient quantities at favorable prices for terms of three or even five years. In addition, many of the proposals for power supply were associated with new generation units that depended on the revenue from DWR contracts in order to secure financing. In most of those cases, sellers were seeking ten-year or even longer terms to satisfy lenders. If DWR's preferences for shorter term contracts had been met by the market, the amount of the net short energy needs after 2004 to be served by either the spot market or new long-term contracts to be entered into by the IOUs in 2003 or beyond would be significantly greater.

17 The Report's contention that DWR should have entered into more contracts for a greater portion of the net short capacity needs beyond is simply inconsistent with the direction of the Legislature in AB 1X to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour. This position is also inconsistent with the public statements made by the California Public Utilities Commission, which has voiced its desire for virtually all of DWR's contracts to be terminated as of the 2004 or 2005 timeframe if it were possible to do so.

DWR Requested and did not Receive the Full Cooperation of the IOUs and ISO

DWR recognizes that it is only one of several parties with a responsibility for the procurement and delivery of electricity in the State. From the onset, DWR sought to establish working relationships with the major market participants, each of whom have their own mission independent of DWR. Resolution of the many issues faced by DWR required getting information and agreement on major issues from these parties. The Report is either silent on these varied and complex relationships, or suggests a simplistic approach in which all parties initially agree on the resolution of significant, large dollar issues. Given each party's different mandate and legal responsibilities, this simplistic approach is not feasible. DWR has ongoing, meetings and negotiations on varying issues with the following parties: (18)

- ISO, which is subject to the purview of FERC, and thus guided by federal regulations and not required to assist in the administration of AB 1X.

- CPUC, which interprets its roles and responsibilities under AB 1X differently than DWR.

- IOUs, whose dealings with DWR are subject to CPUC, and in the case of PG&E, direction and rulings of the Bankruptcy Court.

DWR believes that the Report is especially unfair in its criticism of DWR for not coordinating better with IOUs in integrating the power supplies under DWR's contract with the utility retained generation. The Report cites the benefits of optimizing the use of the URG to meet ancillary services (capacity reserves), and molding the operation of such flexible resources as hydroelectric power plants around DWR's purchases to enable a more cost effective supply. DWR could not agree more. Optimization of the value of URG and DWR's contracts requires a three-way coordination between DWR, each respective IOU, and ISO. Neither IOUs nor ISO have provided such cooperation despite repeated requests from DWR. Without cooperative parties, there can be no coordination. (18)

IOUs have steadfastly been unwilling to provide information on their plans for dispatch of their URG. Even when DWR agreed to furnish or fund the costs of all of the ancillary services not otherwise provided by the IOUs' own generating resources, SCE and PG&E have both refused to develop plans to coordinate their hydroelectric plant operations to optimize the combination of net short energy generation and ancillary services provision. The IOUs have stated that they have no economic incentive to perform such optimization due to CPUC rules regarding their compensation for operation of their generation resources.

Compounding this lack of IOU cooperation is the total lack of cooperation by the ISO. If DWR could not receive information from IOUs regarding their operation of URG resources, ISO could have provided IOUs schedules for such operations to DWR to

both plan around and dispatch around. ISO, citing its FERC tariffs, repeatedly refused to provide this information to DWR. ISO maintains that DWR is a market player like any other and has no right to the confidential information of another market player's (in this instance the IOUs) scheduling information.

Thus, while a coordinated effort between IOUs and DWR to optimize the value of the URG and contract resources to ratepayers through an integrated dispatch procedure makes ultimate common sense, neither IOUs, ISO, or even FERC will allow this to
18 happen. The Report fails to acknowledge this and instead criticizes DWR for this lack of coordination. DWR has no authority to compel IOUs or ISO to cooperate.

Events Have Overtaken the Recommendations in the Report

The Report makes a number of recommendations for actions that have already been initiated by DWR. Examples of these circumstances are provided here.

19 **Assessment of the Contracts –** The Report recommends that DWR undertake an assessment of its contracts. DWR began in September to perform a systematic economic review of its contracts similar to that recommended in the Report. Such an evaluation is typical for any holder of a portfolio of power supply contracts. DWR has regularly evaluated the contracts for performance in accordance with the terms, comparison of the contract price to the market, assessment of the accuracy of invoices, and related evaluations. This evaluation has included a comparison of the portfolio to the projected needs for net short energy and ancillary services as the shape and needs of the customers of IOUs have changed with the increased opportunity for direct access by IOU customers based upon the September 20, 2001 decision by CPUC regarding suspension of direct access.

Contract Renegotiation Strategy – The Report recommends that DWR develop a strategy for renegotiating its contracts. In October DWR commenced development of a renegotiation strategy, based in part upon the systematic evaluation of the contracts noted above. Legal counsel is assessing this evaluation and associated actions and discussions with DWR's contract counterparties are planned.

Legal Contract Management Strategy – The Report recommends that DWR proactively manage its legal risks. Since September, DWR has added six additional legal counsel to its team, including three additional internal counsel reassigned from other duties and three outside counsel. These attorneys have the responsibility for evaluation of contract compliance, assessment of the rights of DWR under the contracts, and litigation specialists in the event of challenge by counterparties.

Focus on Short-Term Transaction Operations – The Report recommends further development of DWR's short-term transaction operation. DWR commenced efforts in September to focus on the difficulties that have been created by the lack of cooperation by ISO and IOUs in the real-time energy and ancillary services coordination and settlements process. DWR established a team composed of its accounting, energy advisors,

internal and outside counsel, and its settlements staff to take the initiative to modify the arcane ISO settlements process as it pertains to purchases and credit-backing by DWR to foster more rapid payment to market participants and to avoid double invoicing that had been occurring by ISO. A process to break this settlements logjam had been developed with ISO, had the tentative agreement of IOUs, and was being reviewed by the sellers into the ISO markets in October. On November 7, 2001 in response to a petition by a group of generators, FERC ordered ISO to invoice DWR for all charges ISO believed were owed to it by IOUs. This order negated three months of intense efforts and negotiations to correct the troublesome ISO settlements process. DWR has made the initial required payment on a November 21, 2001 invoice received from ISO. The FERC and ISO actions will likely establish another round of assessment of the procedures for ISO settlements.

Collaboration with the IOUs and CPUC on Rate Incentives for Dispatch of the URG – The Report recommends collaboration with IOUs and CPUC to achieve least-coast dispatch. The matter of rate treatment for the IOUs URG is being addressed in a formal proceeding before the CPUC (A0011056). The matter of collaboration and coordination of the dispatch of URG has been expressly included in the discussions pertaining to the ISO settlements process. The November 7, 2001 order by FERC and the subsequent ISO invoice of November 21, 2001 effectively obliterated any achievements made between DWR and IOUs on negotiating arrangements for proper incentives for payment by autocratically requiring DWR to fund any and all ISO charges regardless of merit or DWR's responsibility for such charges. Despite this setback completely outside of DWR's control, DWR remains committed to working with IOUs, ISO, and CPUC in developing the proper incentives for IOUs to dispatch its URG in a manner which those power resources and DWR's contracted supply can be reasonably optimized. The constraints of the ISO system and its operating protocols and real-time market structure has been and is expected to continue to be a major obstacle to such optimization.

Legislative Action to Extend the Department's Role to Assure Transition – The Report recommends that the Legislature develop an appropriate statutory framework to extend DWR's purchasing. DWR has already commenced a program targeted to assure timely transition of its role as power purchaser of the residual net short (the remaining net short after consideration of DWR's contracts) to others. The Legislature may select other parties for this purpose, but absent such alternative Legislative direction, DWR has assumed that IOUs will resume the obligation to purchase the net short upon their achieving creditworthy status. The timing of the transition is not fully certain, given the uncertainty of the resolution of the PG&E bankruptcy and the time it requires SCE to implement the settlement process negotiated with CPUC in October. However, it is likely that SCE will become creditworthy prior to DWR's January 1, 2003 sunset provision of AB 1X. The timing of the PG&E bankruptcy resolution is unclear, although it is possible that PG&E could resume the purchase of net short energy with the bankruptcy resolution pending if the retail customer revenue for such payments could be satisfactorily protected from other creditor claims. San Diego Gas & Electric Company could return to the role of purchasing the net short having received its rate adjustment.

The issuance of DWR's bonds for payment of energy purchases will likely be a necessary precursor to returning the three IOUs to the position of purchasing the residual net short due to the positive effect this bond issue is expected to have on the California energy market in general.

CPUC has initiated a proceeding to address the process by which IOUs would return to the role of purchasing the net short. DWR is cooperating with the CPUC staff in evaluating the method by which DWR's contracts, IOUs' URG, and the residual net short purchases can be combined in a manner which accelerates this transition.

Other matters being addressed by DWR in this transition effort, as well as being a part of proper disclosure for DWR's bond issue include the need for proper planning and implementation of, but not limited to, the following:

- overlap of DWR trading floor operations with those of IOUs to effect a smooth transition;
- information systems coordination and data transfer;
- clarification of coordination of dispatch responsibilities among DWR, IOUs and ISO;
- ISO, IOU, and DWR settlements coordination; and
- off-system sales coordination.

Retention of Legal Counsel for State and Federal Regulatory Issues – The Report recommends DWR retain counsel to advise DWR on matters associated with State and federal regulatory matters affecting the power-purchasing program, distinct from the interests of the State Water Project. DWR already has multiple legal firms advising on such matters. DWR is represented in State regulatory matters by the law firm of MBV Law, which is separate and distinct from matters associated with the State Water Project, in that the State Water project has no role with CPUC. The firm of GKRSE represents DWR on FERC matters. The fact that counsel may also advise the State
20 Water Project on federal matters not pertaining to the role of DWR is irrelevant. Using counsel familiar with the California market and the respective roles of IOUs, ISO and DWR is simply efficient business practice.

Seek Clear Authority to Use Financial Instruments to Manage Transaction Risk – DWR agrees with the Report's recommendation to gain clear authority to use financial instruments to manage gas and electric transaction risks. DWR is in the process of obtaining legal clarification from the State Attorney General's office of the existing statutory authority vested in AB 1X for this very purpose.

COMMENTS

California State Auditor's Comments on the Response From the Department of Water Resources

To provide clarity and perspective, we are commenting on the Department of Water Resources (department) response to our report. The number corresponds to the number we have placed in the response.

(1) The department is incorrect. Although we acknowledge in the report that the department's decisions contributed to improvements in the market, the evidence suggests to us and other reviewers that various events happening in the spring of 2001 converged to improve price stability and system reliability. As such, we could not attribute as much of the improved price stability and system reliability solely to the department's actions as it believes is warranted. Furthermore, we did not perceive our mission as trying to identify which of these events should get credit for the improvement, or how much credit should be attributed to each. Rather, we focused on the potential risks in the portfolio of contracts the department developed in crisis conditions and on how the State should best manage those risks for the future of the power-purchasing program.

Further, the department is incorrect that we did not take the crisis environment into account when evaluating the reasonableness of its decisions. Throughout our report we acknowledge the context of the crisis and the immense challenges the department faced. Given that context, we believe the standard for evaluating its implementation of Assembly Bill 1X (AB 1X) goes beyond the success of stabilizing prices and reliability in the spring of 2001. While the department is entitled to disagree, we believe it is also important to know the long-term consequences of the department's actions. As such, our report includes an analysis of the products purchased for a value of $42.6 billion over the next 10 years and a review of the terms and conditions of the contracts.

With respect to the portfolio, because the department chose to use a significant number of long-term contracts to resolve the energy crisis, we believe it was relevant to analyze the long-term risks in the $42.6 billion portfolio it assembled. Specifically, we

saw the need to determine the extent to which the portfolio has risk that the program currently has too much power during low demand periods and will still need to buy more power in the real-time market during periods of high demand. Given these conditions, there exists significant risk that the department may have to resell power at a loss or purchase additional power during times of supply shortages and rising prices. With respect to the contracts terms, we believe it was relevant to analyze the contractual safeguards designed to ensure that California will get reliable power from generators, particularly in times of tight supply and rising prices. We believe this a relevant test of the effectiveness of the department's contracts since those were the conditions that contributed to the crisis that AB 1X was trying to resolve. Our analysis is totally consistent with the objectives of the power-purchasing program as stated by AB 1X.

(2) The department is incorrect in its assertion that we were silent on the topics that it considers its major achievements. Contrary to the department's assertion, we considered these five facts when reaching our conclusions and our report specifically addresses four of the these five facts as follows. Specifically, we discuss spot market prices coming down on pages 133 to 137, we discuss the department's electricity costs on pages 132 to 135, we discuss the department's purchases of power on pages 132 to 134, and we discuss the new power plants that will provide the contract power on pages 36 to 37. In addition, we acknowledge in the report title and on pages 59 to 60 of the report how the energy crisis has eased, but as the department points out, we do not specifically mention that there have been no recent blackouts. The pages listed are only the examples of where we discuss these issues; the report includes many other references to these issues. Therefore, we believe our report gives appropriate coverage to each of these facts.

(3) The department appears to take credit for these plants being built; however, as we point out on pages 92 to 93, we concluded that many of the contracts do not contain the terms and conditions needed to ensure completion of these new power plants.

Further, data we compiled from the department's contracts reflect that the contracts provide significantly less peaking capacity than the 1,300 megawatts the department indicates. Specifically, from both existing and new facilities, the department's contracts will provide only about 1,000 megawatts in 2002 and thereafter about 770 megawatts per year through 2010.

(4) We disagree with the department's statement that we did not acknowledge the existing market system and the effect of the Federal Energy Regulatory Commission's (FERC) involvement in the California market. While we did not capture every instance, on numerous pages throughout the report we mention FERC's involvement in the California energy markets. Moreover, the scope of our audit is limited to how well the department implemented AB 1X. Critiques of actions by state or federal regulatory agencies are not within that scope. Based on the department's comments, as a significant market participant, it appears to have a need to interact with these regulatory agencies in an attempt to improve the market structure in California. In its response, the department is silent as to whether it has attempted to work with FERC to resolve the market inefficiencies it identified.

(5) The department's statement is misleading. While it claims to have assembled a comprehensive business plan to carry out its mission under AB 1X, the department's strategy is contained in a wide array of communications, such as task-specific documents, memorandums, e-mails, and minutes of meetings.

(6) This figure mistakenly gives the impression that the department's long-term contracts supplied a significant amount of power during 2001. We believe that the department is using the label "contracts" to describe any transaction for power that is not from the spot market. Using the department's data, our report more clearly shows the breakdown between short- and long-term purchases. Specifically, we indicate on page 35 that through October 26, 2001, the department bought 84 percent of its power in 2001 from short-term contracts, block-forward contracts, and the spot market, with the remaining 16 percent coming from the long-term contracts. Further, Figure 14 on page 134, provides additional detail of the type of agreements the department used to purchase power for the first eight months of 2001.

(7) We are pleased that the department acknowledges the difficulty of this audit for us; we, of course, also acknowledged the unique and substantial challenge the department faced in its implementation of AB 1X. However, the department is mistaken in its

assertion that our team was not qualified to conduct this audit. As the department knows well, neither its own capable personnel nor its many qualified consultants had experience with the unprecedented market crisis that existed in California, even though they derived their experience primarily from the California market.

Recognizing the complexity of the subject matter of this audit, we conducted a national search for technical and legal consultants to assist with this assessment, seeking the experience, capabilities, and independence necessary for the successful conduct of this audit. We concluded that it was crucial for public confidence in this audit to retain consultants with relevant experience in both competitive and regulated markets, primarily outside of California. It was important to us that the consultants had not represented and do not now represent any power producer, marketer, buyer, or utility on California power market issues.

Our consultants, LaCapra Associates and Pierce Atwood, came to us well recommended by their clients in competitive and regulated markets throughout the United States. Through our consultant selection process and our work with them in this audit, we are confident that our consultants have been well suited to the task. Our technical consultants provide services to a full range of organizations involved with energy markets—public and private utilities, energy producers and traders, financial institutions and investors, consumers, regulatory agencies, and public policy and research organizations. Their technical skills include forecasting models and methods, economics, finance, law, planning, pricing, engineering, procurement, and contracts.

Our legal consultants generally, and the team working on the audit in particular, have had extensive experience with power purchase agreements over the last 20 years in a wide variety of capacities in New England, nationally, and internationally. Since 1997 much of their work has focused on the effects that restructuring and deregulated markets have had on power contracts.

During the audit, the department had every opportunity to meet with us and our consultants to provide information and explain the unique context of its efforts; and we and our consultants made every effort to gain that understanding from the department in the time allowed for this audit. We are concerned that the unfounded assertions about consultants' qualifications are an

indication that the department is unreceptive to our observations and recommendations for improvement of the program. We hope this is not the case.

(8) We are disappointed that the department chooses to still disagree with the wording of the chapter titles in the report. We met repeatedly with department staff from December 5 through December 9, 2001, to discuss the report content and gave them ample opportunity to suggest changes to the chapter titles. In fact, based on those meetings, we changed the wording of two chapter titles to language that better reflected the content of the chapters.

(9) We disagree with the department's assertion that our analytical approach is "fundamentally flawed based on (i) basic misunderstanding of DWR's [the Department of Water Resources] role and mandate; (ii) a failure to appropriately acknowledge circumstances beyond DWR's control that limited [its] ability to act more effectively; and (iii) misrepresentation of fact." The department's statement appears to be based on the arguments on pages 237 to 244 of its response. We previously addressed in our first comment how we understood the department's role and how the report places in context of the crisis environment. Further, in several meetings with department staff, we gave department staff ample opportunity to review the report and identify any factual errors, as is a normal part of our quality control process. Moreover, we are required by law to follow generally accepted government auditing standards. These standards require that we obtain sufficient, competent, and relevant evidence to afford a reasonable basis for our findings and conclusions. In the following comments, we further address how the department has misunderstood the report's conclusions and improperly characterized our report as "fundamentally flawed" in its arguments on pages 237 to 244 of its response.

(10) While we agree that the primary purpose of AB 1X is to provide reliable energy at the lowest possible prices, we disagree that we failed to identify an appropriate standard for evaluating the department's performance and success in implementing the objective of AB 1X. We used the considerations for a contract portfolio spelled out by AB 1X as a measure of the department's performance. In its response, the department seems to point to avoiding energy blackouts as success in its primary mission. However, the department's measure of success is short-term in that it appears to focus on the market crisis conditions that existed earlier in 2001, and neglects to consider the long-term

consequences of its contracting efforts. As discussed in Chapters 1 and 2, while giving the department credit for keeping the lights on we point out that the department's contract portfolio contains market and reliability risks.

(11) We have recognized in several places throughout the report that the department believed that to achieve the goals of AB 1X, the crisis in the electricity markets required it to move quickly to enter long-term contracts to calm the market. We agree with the department that in reviewing the department's implementation of AB 1X it was important to understand the environment in which that legislation was enacted, as reflected in the legislative findings and declarations made in Section 80000(a) of the Water Code. At the same time, it is critical to understand the express mandate and powers handed to the department, as reflected in Division 27 as a whole and as specifically addressed in Section 80100, which, among other things, states "[t]he intent of the program . . . is to achieve an overall portfolio of contracts for energy resulting in reliable service at the lowest possible price per kilowatt-hour." As to achieving a portfolio "at the lowest possible price per kilowatt-hour," on page 39 we recognize that the department nearly achieved its target price of 6.9 cents per kilowatt-hour.

However, that was not the only directive AB 1X gave to the department. Under both the terms of AB 1X and based on our review of the crisis environment in which the portfolio was assembled, we concluded that assembling a portfolio of energy products and contracts with terms and conditions assuring reliability of performance by sellers was critical to the department's prime mission of keeping the lights on in California. The environment in which the contracts were made (an unstable market, tight supply, large unscheduled outages, and volatile prices) underscores the need for reliability. Moreover, because the long-term contracts will continue to impact the State over the next decade, in evaluating the department's implementation of AB 1X, we concluded that we could not simply focus on the immediate benefit the department's implementation of AB 1X may have had on the California energy market. We concluded that it is also critical for the State to understand and address the risks that the State will continue to face over the next decade, risks that arise from the crisis itself and the actions the department believed it was compelled to take to address the immediate crisis. Thus, in moving forward, we concluded that it is important for the State to understand whether it has the right mix of products to assure the needs of the State over the next 10 years, especially

at the times when those needs are most significant. Likewise, in reviewing the terms and conditions of the long-term contracts, we concluded that it was important to understand the extent to which they will assure reliable performance from generators over the next 10 years, particularly in times of tight supply and rising prices.

(12) The department incorrectly implies that we did not consider the difficult environment in which it operated the power-purchasing program when it states that we should have considered a number of very unique and difficult conditions in our appraisal of its performance. Our recognition of the hardships facing the department in carrying out AB 1X is included in the Introduction and leads all four chapters of our report. Further, in certain places in our report we provide detailed descriptions of the department's challenges. For example, on pages 27 through 29 we describe the extraordinary circumstances that complicated the department's efforts to assemble its contract portfolio. On pages 122 through 132, we describe the magnitude of its task and challenges in structuring and staffing the division.

(13) Contrary to the department's statement, we believe that our report appropriately "recognized the discretion that AB 1X understandably vested in DWR [the department] to choose a path for combating the crisis." Specifically, on pages 24 to 25 of the report, we list the criteria contained in Section 80100 of the Water Code and on pages 25 and 71 we believe that we clearly acknowledge that AB 1X gave the department broad discretion over the portfolio goals to pursue. In addition, to further describe the department's discretion in how to assemble the contract portfolio that AB 1X requires, we explain on pages 31 to 33 the range of portfolio decisions that were available to the department. Therefore, our audit focused on the risks resulting from the department's decisions regarding how quickly it would design a portfolio and sign contracts.

(14) The department misses the point. The question is not whether a particular term assures reliable delivery of power, but whether the terms and conditions of the contracts as a whole work together to assure reliable delivery of power and provide the State with tools to effectively manage the contracts. As stated in the report at pages 86 to 87, the terms of reliability in long-term energy contracts are multiple and varied, and include, for example, availability guarantees, performance standards, penalties and incentives for performance, excuses for nondelivery, events of default, and damages and other remedies. In fact, the contracts

negotiated after March 2, incorporated many of the industry standard reliability terms we were looking for in our review—a strong indication that the department thought those terms were important. However, the department never fully explained nor provided evidence as to why these types of reliability terms were not specifically requested or included in the contracts until the majority of the contracts were executed or agreed to in principle. Instead, the department's response focuses on termination rights and cover damages as if they were the only terms relevant to crafting a long-term energy contract that assures reliable delivery of power.

Moreover, we disagree with the department's view that a cover damages remedy adequately assures the reliable delivery of power in the future, particularly when viewed in the context of contracts that in general lack the reliability terms that are used regularly in the industry, and appear in some of the department's own later contracts. To make its point, the department couples termination for repeated or intentional failure to deliver at critical times with termination for failure to pay cover damages. However, there is an important distinction between the right to terminate for a seller's failure to deliver power and the right of the department to terminate the contract if the seller refuses or fails to pay cover damages for the costs the department incurs in securing necessary replacement power. In other words, under most of the contracts, the department would not have the right to terminate if a seller deliberately withholds power at a time of critical need and a blackout results and instead only has a right to terminate the contract if the seller refuses to pay the department for its actual cost to buy the power from another generator.

As explained on pages 89 through 92, our review of the contracts led us to conclude that a seller was not likely to refuse to pay cover damages and run the risk of having the contract terminated and losing their more lucrative long-term profits under the contract. Our review also led us to conclude that a right to terminate for repeated or deliberate failures to deliver at critical times would have given the department better negotiating leverage to coerce sellers to perform. As we state on page 91, most of the early contracts are for lower than market prices in the near term and for higher than market prices in the long term. To ensure delivery at the low prices in the near term, the ability of the department to threaten that it will terminate the generator's lucrative profits in the long term could have been a powerful tool in assuring seller performance. Finally, while the department asserts that actual seller behavior disproves our concerns about the effectiveness of

the cover damages to assure seller performance, as we state on page 70, we believe that the effectiveness of that remedy has not been truly tested under the limited timeframes and the market conditions that have existed to date.

(15) Although we do not believe the manner in which we labeled the department as "the provider of last resort" was inaccurate or misleading, we deleted the phrase in the few places it was used in the report to avoid confusion and because doing so did not change our conclusions.

(16) Whether or not the form agreement the department selected was the best form agreement misses the point. The point is that the negotiating team (including its legal consultants) did not modify the form agreement to include the kind of terms that would have better assured *reliable delivery of power* as a starting point for negotiations. As stated on page 103, we believe that the volatile conditions that existed in the California market in particular should have led the department to modify the form agreement, which was primarily designed to promote liquid trading of electricity in a well-functioning electricity market. The department incorrectly suggests that we disagree with the department's decision to use the Edison Electric Institute (EEI) form. In fact, on page 105 we recognized the department had several valid and prudent reasons for choosing to use a standard form contract.

However, as discussed on pages 79 to 80 and 105, we concluded that the industry standard form selected by the department should have been modified to address the unstable market environment that led to the enactment of AB 1X and the department's role as the purchaser of the physical, net-short position for the investor-owned utilities. We believe that if the department had modified the form agreement at the outset, it would have increased the likelihood that it could have successfully negotiated including the kind of reliability provisions that are not only commonly used in the industry by entities that must assure reliable delivery of power, but that we saw in the department's own later contracts. While we recognize that the forms were modified to address the daunting creditworthiness issues the department faced, we concluded that they also should have been modified to address the reliability goals stated in AB 1X as a starting point for negotiations. Because the form agreement was not modified and those types of terms apparently were not sought until later in the contracting process, we cannot say whether the department could have successfully negotiated such terms for the earlier, larger contracts.

Moreover, we saw no evidence that in reaching the conclusion that the unmodified form was adequate to protect the department's interests, that the negotiating team (including its legal consultants) ever actually reviewed, compared, or discussed specifically modifying the form contract to include the specific reliability terms we saw in other utility contracts, the ISO contracts, the summer reliability agreements, and some of the department's own later contracts. Finally, the form contract the department selected was both very new and not widely used in the west. In fact, the EEI form was only released for use in April 2000. But that said, we have not questioned the decision to use that form agreement, but simply the decision that it was adequate without modifications to protect the department's needs, especially in times of tight supply and high prices—the very conditions the contracts were supposed to address.

(17) The department misunderstands our conclusions. Contrary to the department's statements, we did not criticize it for "not planning for the development of additional power plants beyond 2002" and "not providing for contracted power through 2010." Further, we did not contend or imply that the department "should have entered into more contracts for a greater portion of the net-short capacity needs" in the general sense that the department characterizes. Rather our observations focuses on the cost risks that exist in the portfolio of contracts that the department assembled. Our findings, restated simply, are (a) the department bought too much power during periods of low demand and now runs the risk that it will have to sell excess power at a loss, and (b) the department did not buy enough power during periods of high demand and runs the risk that it will have to buy power at high prices. These cost risks are a consequence of the contract portfolio that the department assembled in response to the crisis.

(18) We do not agree that we remained silent on the complex relationships between the department, the investor-owned utilities, and the California Independent System Operator. On the contrary, on pages 152 through 156, we discuss the need for cooperation between the department and the investor-owned utilities to coordinate the department's resources with the utilities' generation to provide the least-cost electricity to retail customers. However, we modified our heading in this section in response to the department's sensitivity that we unfairly place excessive responsibility for the current lack of coordination on the department.

(19) While we appreciate the efforts that the department has made to date regarding the assessment of the long-term contracts, the contract renegotiating strategy, and the legal contract management strategy, for the reasons stated on pages 166 through 176, we believe that the department must continue to strengthen these efforts to appropriately manage the contracts over the next decade. For example, as explained on page 169, it is absolutely critical that the department have the contracts reviewed with a fresh set of highly qualified, experienced, legal eyes so that it can identify all the strengths it can use to its advantage and all the weaknesses it must guard against. Having a legal "second opinion" of sorts on the terms and conditions of the contracts will ensure that the department obtains a fresh, objective view of the strengths and weaknesses that the department must manage. Further, that sort of review of any contract that the department seeks to renegotiate is critical to understanding what the department has to work with. Thus, that review will assist the department in shaping and prioritizing the goals that it should seek to achieve during the renegotiations process. Finally, with respect to the ongoing legal contract management, in view of the size, complexity, and risks inherent in the contracts, to effectively manage the contracts and best protect the interests of the State, the department needs to continue to assemble a legal team that in terms of size, experience, and expertise, is on par with the legal teams the generators are sure to rely on.

(20) We have revised the report to clarify that independent counsel is only necessary when a conflict exists between the goals of the power-purchasing program and the State Water Project.

cc: Members of the Legislature
Office of the Lieutenant Governor
Milton Marks Commission on California State Government Organization and Economy
Department of Finance
Attorney General
State Controller
State Treasurer
Legislative Analyst
Senate Office of Research
California Research Bureau
Capitol Press

California State Auditor

BUREAU OF STATE AUDITS

California Energy Markets

Presentation by

California State Auditor

Joint Legislative Audit Committee Informational Hearing

January 8, 2002

This briefing document is only intended to outline selected portions of Report 2001-009, *California Energy Markets: Pressures Have Eased, but Cost Risks Remain* (December 2001). For a more complete explanation of the points outlined in this document, refer to the report.

AUDIT SCOPE

- California Water Code Section 80270 (amended by AB 1X) requires the Bureau of State Audits to conduct a financial and performance audit of the Department of Water Resources (DWR) implementation of the power-purchasing program.

- Audit focused on critical tasks necessary to implement and manage a program to purchase a sufficient and reliable supply of electric power at the lowest possible price per kilowatt-hour.

- Performed a legal and economic review of the contract portfolio to determine whether contracts provide for reliable power at the lowest possible price per kilowatt-hour.

- Reviewed DWR's strategies, policies, resources, organization and trading tools it used in its real-time power trading and scheduling operations.

- Evaluated DWR's efforts to segregate properly the expenditures of the power-purchasing program from other programs the DWR administers.

- Reviewed DWR's current practice of monitoring potential conflicts of interest.

AUDIT HIGHLIGHTS

- ☑ Although the energy crisis has eased, there remain significant cost risks to manage.

- ☑ DWR responsibilities came at the height of an unprecedented financial and reliability crisis in power markets.

- ☑ DWR's capabilities were dwarfed by the magnitude of its mission under the power-purchasing program.

- ☑ DWR spent $10.7 billion from January through September 2001 purchasing power on behalf of the investor-owned utilities (IOUs) and has assembled a portfolio of 57 contracts totaling $42.6 billion over a 10-year period.

- ☑ The portfolio does not contain sufficient power for peak-demand periods, thus potentially exposing consumers to high market prices if energy supply becomes limited during those periods.

- ☑ Majority of the long-term contracts may not ensure a reliable source of power in times of tight supply and high prices and may not ensure that sellers follow through with construction of proposed power plants.

- ☑ Contracts contain provisions that can increase the cost of power; thus, they need careful management to avoid additional costs to consumers.

- ☑ Contracts convey lucrative financial terms upon suppliers to ensure that energy is delivered.

- ☑ Under most of the contracts, the DWR cannot terminate the contract or assess penalties even if the generators repeatedly or deliberately fail to deliver power at times when the State is in dire need of it.

- ☑ DWR lacks the necessary infrastructure and staff to manage its energy purchases in the short-term market.

RECOMMENDATIONS

Policy

Legislature and governor should consider developing a long-term strategic framework for the electricity industry in the State and for the DWR's role in that system.

Legislature should consider amending AB 1X to extend DWR purchasing authority to allow time for development and implementation of a strategic framework to assure continuity of purchasing function and an effective transition presumably back to IOUs.

Department of Water Resources should:

- Create a strategic plan for the future of the power-purchasing program, including an assessment of the transition processes needed to allow an orderly transfer to IOUs, the California Independent System Operator (ISO), and others as appropriate.

- Continue its efforts to coordinate with the power authority to clearly establish the roles and responsibilities of each organization.

Portfolio Planning and Management

Department of Water Resources should:

- Conduct within 90 days an in-depth economic assessment of contracts and overall supply portfolio to assure that the DWR develops an effective contract management strategy. Assessment should focus on how contracts fit into the overall portfolio and on costs relative to current expectations of market conditions.

- Develop a contract renegotiation strategy that focuses on improving reliability and overall performance of the portfolio.

- Establish a planning process that more directly integrates the entire portfolio of supplies serving customers of the IOUs with the role of the long-term contracts.

Power Contracts

Department of Water Resources should:

- Conduct within 90 days an in-depth assessment of legal risk and legal services requirements to ensure that it can develop an effective strategy for managing contracts.

- Establish an ongoing legal services function that specializes in power contract management, negotiation, and litigation. To avoid conflicts, this legal function should be separate and distinct from counsel retained to sell bonds or to provide legal advice to the State Water Project.

- Investigate all rights under contracts to assure that it can develop a proper program to enforce performance.

Short-Term Transactions

Department of Water Resources should:

- Enhance the organization's skills for market analysis and contract management to address the implications of uncertainty on portfolio management and dispatch decisions.
- Develop a transition plan for the orderly transfer of the short-term purchasing and net short management functions to the IOUs and the ISO, or others as appropriate.
- Collaborate with the IOUs to share information about generation sources and to organize least-cost dispatch. IOUs need to commit to this effort.
- Coordinate with IOUs and the California Public Utilities Commission to ensure that rate incentives associated with Utility Retained Generation are resolved so that lowest cost energy is dispatched.
- Collaborate with market participants to resolve settlement problems associated with energy and ancillary services functions that DWR conducts on behalf of ISO.

DWR Operations

Department of Water Resources should:

- Retain independent legal counsel to advise DWR on matters pertaining to state and federal regulatory issues that affect the power-purchasing program.
- Seek clear statutory authority to use financial instruments to manage gas and electric transaction risks.
- Amend servicing agreements to include language that promotes accuracy in estimates of customer usage.
- Develop audit procedures to review periodically the IOUs performance of critical elements in the servicing agreements such as cash remittance methodologies, allocation of the power that the DWR purchases, and the cost of energy conservation programs.
- Coordinate with IOUs to develop audit procedures to detect noncompliance with critical elements of the servicing agreements.
- Complete its efforts to execute agreements with the IOUs that cover power purchases designed to balance in real time the electricity power supplied to the grid with total customer usage.
- Continue its efforts to review potential conflicts of interest among all employees and consultants twice each year and retain a record of its review.
- Improve its controls designed to have all power-purchasing costs appropriately charged to the program and supported by evidence of service.

PORTFOLIO OF POWER

The DWR became responsible for providing the net short for retail customers of the IOUs.

Portfolio Contains Numerous Risks That Must Be Managed and Mitigated

Portfolio strategy indicates that DWR elected to emphasize long-term contracts as a means to secure new generation capacity for greater reliability and long-term price stability.

Most of the power procured to meet the net short in 2001 was supplied from spot market and short-term forward contracts (Figure 16):

- Through October 26, 2001, approximately 84 percent of net short was purchased through short-term contracts, block forward, and the spot market.

Portfolio includes a significant amount of capacity from new units. (Figure 1)

DWR's consultant estimates that the cost of contracts over the 10-year period ending December 31, 2010, to be approximately $45.6 billion or $70 per megawatt (7 cents per kilowatt).

Current result of procurement efforts appears to be a set of contracts that are largely priced higher than the market with respect to a recent projection of market prices prepared by the DWR's consultant. (Figure 2)

Contracts Provide Ample Energy But Less Ample Capacity

At all times system operators must ensure that sufficient generating capacity is operating to meet consumer demands. (Figure 3)

Net-short energy is the total amount of electric production required above that produced by the IOUs over a period of time, such as a year. (Figure 4)

Net-short capacity is the peak demand of power in any given hour above that produced by the IOUs. (Figure 5)

Calculations by a DWR consultant reflect that the contracts will not cover a substantial portion of the estimated load during hot summer days when demand for electricity is at its maximum.

Portfolio lacks a significant component of true peaking capacity to supply energy during peak demand or extensive generating unit outages.

Conversely, the energy purchases during the 6 X 16 peak period will exceed the average net-short position during certain hours for several years:

- The potential for energy surplus is particularly high in the southern part of state—south of the Path 15 transmission interface. Some estimates indicate that power purchased under long-term contracts will exceed the average net-short position by an average of 2,000 megawatts from the last quarter of 2003 through the first quarter of 2005.

Portfolio of contracts appears to overemphasize year-round energy, underemphasize delivery during peaking hours, and underemphasize capacity requirements as they change with time.

A more effective strategy would have placed a greater emphasis on the procurement of supplies to meet daily and seasonal peak demands.

- DWR acquired little by way of capacity contracts to respond to consumer demand during the most critical future peak demand periods—summer and super peak periods, when the net-short capacity requirements might be unusually high.

- IOU customers remain exposed to supply shortages and purchases in the spot and other short-term markets when prices are high. System reliability also might be threatened if insufficient generating capacity is available on short notice to meet the DWR's needs.

Portfolio Lacks the Flexibility To Substantially Reduce Purchases

Majority of contracts provide for delivery of firm energy—the DWR must pay for the power whether or not it is needed.

Retail consumers are unlikely to benefit significantly from the expected fall in spot electricity prices over the next 10 years because spot market purchases will, on average, account for 9.5 percent of total energy requirements.

DWR purchased too much power in Southern California:

- The amount of capacity under contract to serve loads south of Path 15 from the 4th quarter of 2003 through the 1st quarter of 2005 will exceed average peak demand resulting in significant energy surpluses.
- DWR did not consider the Path 15 problem in its portfolio design because it believed that the Path 15 upgrade would be completed in time for its power purchases beginning in 2003.

Although natural gas prices have fallen, only 30 to 40 percent of contracted capacity in megawatts include provisions designed to follow trends in gas prices. (Table 4)

Portfolio includes little renewable energy: only 6 contracts totaling 2 percent of all megawatts purchased.

LONG TERM CONTRACTS

Terms and Conditions In Contracts May Not Ensure Reliability

- ❑ Contract terms were successful in establishing DWR as a creditworthy buyer.

- ❑ Contracts may not assure reliable delivery of power especially in times of tight supply and high prices.

- ❑ Assessment of contracts is not simply their impact in 2001 but rather how the terms will affect California over the next 10 years.

- ❑ Five provisions that should be in contracts to increase assurance that seller will perform (Page 86):
    - Favorable terms to seller (high price, lenient delivery).
    - Cover damages.
    - Monetary rewards and penalties to assure performance.
    - Performance standards to assure seller performance.
    - Right to terminate for repeated failure to perform.

- ❑ Majority of contracts may not ensure a reliable source of power in times of tight supply and high prices and may not ensure construction of proposed power plants.
    - Contracts do not include terms and conditions that would ensure that generators are making progress in building facilities and allowing the State to inspect facilities unable to produce power because of mechanical failures.
    - Some contracts for which the State paid a premium for construction of new generation may not ensure that the new units will be built and that power will be made available and delivered.

        In some cases, the contracts can provide disincentives to perform. For example, DWR could be exposed to risk that it will have to pay Calpine $1.56 billion in exchange for little or no new generation. (Page 93)

- Some contracts based on new generation do not expressly provide that failure to build the generation is an event of default or a trigger for other penalties.

- Under most contracts a seller must pay cover damages for failure to deliver, but the State cannot terminate or penalize generators even if they repeatedly or intentionally fail to deliver power when the State is in dire need of it.

  Cover damages: generator has to pay difference in contract price and amount the State pays. (This remedy does not address "reliability" rather it addresses "price stability." It also assumes adequate supply of power.)

  If repair costs to get generation back on-line exceed the cost of cover damages, the supplier may chose to pay cover damages rather than incur those costs.

  Best means to ensure delivery is to make repeated or intentional failure to deliver an event of default. If there is the possibility of losing a lucrative long-term contract, then the generator has more incentive to keep power on-line.

Portfolio Of Contracts Contains Significant Cost Risks That Need To Be Closely Managed

DWR's contracts provide lucrative terms for ordinary performance:

- Long-term high megawatt contracts with significant long-term income.

- Favorable price terms.

- Reduced risk associated with future generation and delivery costs.

- Enhanced seller termination rights.

Many contract costs are not fixed and shift risks and costs to the DWR:

- Contracts require DWR to pay for any new taxes that California may levy that affect generation and delivery of power.

- Some contracts require DWR to pay for any emissions charges or environmental upgrade costs the seller incurs as a result of generating power for the DWR.

- Calpine contract price increases if any governmental action results in increase of Calpine's cost of service greater than 50 cents per megawatt hour.

Sellers have broad rights to terminate by declaring an event of default and the financial consequences of a seller declaring an event of default would be significant:

- DWR fails to comply with material provision of contract.
- DWR fails to make payment after written notice.
- DWR fails to satisfy creditworthiness requirements.

DWR (in early contracts) has few if any rights to declare an event of default.

Form Contracts Lacked Important Terms

DWR started from a weak bargaining position when it did not request industry-standard contract terms and conditions. Model contracts used were designed for functioning markets where purchase of electricity is treated as a financial transaction:

- DWR chose to use model contracts without modifying them to meet the State's reliable energy needs.
- DWR proposed "seller-friendly" contracts that lacked reliability terms and thus are not adequate instruments for a buyer in an unstable market with insufficient supply.
- DWR apparently did not identify a need to modify the form contract to include industry-standard provisions to ensure reliability. (Later contracts did include terms regarding reliability.)

By not requesting reliability terms, DWR had no way of knowing if generators would be willing to accept such terms. Also, negotiators and legal consultants did not have a checklist of provisions that should have been negotiated on as agreements in principle were crafted into contracts.

Form contracts lacked five provisions to ensure reliability:

- Define failure to deliver as an event of default.
- Assess penalties for unexcused failure to deliver.
- Provide availability guarantees (ability to produce and deliver).
- Require operation and maintenance within prudent industry standards.
- Give DWR the right to inspect and monitor generator.

Form contracts lack three provisions to ensure construction and maintenance:

- Mandate construction and penalizes for failure to complete the unit.
- Construction milestones.
- Permit specific performance.

Speed of Contracting Process Had an Adverse Impact on the Nature of the Deals and the Terms and Conditions of the Contracts

Failure to achieve buyer-friendly terms appears to be due to speed and failure to request terms in the request for bids and the negotiation process:

- First 30 days the State negotiated and agreed in principle on 35 contracts for $35.9 billion. (Figure 9)
- More than 80 percent of power was negotiated in principle during intense contracting period from January 24 to March 2, 2001.
- Contracts negotiated prior to March 2, 2001, provide highly favorable financial deal for generators and it is this incentive rather than the terms of the contracts that will compel them to deliver power.

Negotiators believed that the principal mission of the DWR was to sign up as much power as possible at the lowest price. What is unclear is why the urgency to move from a letter of intent to a fully executed contract in 7 days when the power would not be delivered for 4 to 10 months.

Problem provisions in Calpine Peaker ($2.9 billion for 20 years, 495 megawatts):

- Allows Calpine to substitute power from other sources.
- Lacked prudent industry practice requirements as to operation and maintenance.
- No availability standards.
- Except for the first year, it does not clearly link reductions in capacity payments for new generation for failure to construct timely or failure to operate.
- Did not provide the DWR the ability to terminate for failure to operate for a period of time.

DWR is exposed to the legal risk that, at Calpine's option it will be obliged to pay $1.56 billion in exchange for little or no new generation because the capacity terms are unclear.

Contract Report Card Shows That Terms In Later Contracts Are More Favorable

Later contracts contain more favorable terms than earlier contracts. Later contracts included performance and reliability guarantees. (Table 8)

After March 2, 2001, DWR carefully reviewed contracts and analyzed problem provisions. Problems in early contracts not repeated in subsequent contracts.

Unfortunately, later contracts are for less power, lower costs, and less duration.

Contract terms did not improve until it was too late to make a meaningful impact on the overall portfolio of contracts.

DESPITE ITS LIMITATIONS, THE DWR MET THE STATE'S POWER NEEDS

DWR's capabilities were dwarfed by the magnitude of its mission under the power-purchasing program.

DWR struggled to fulfill its role as creditworthy purchaser for the net-short position.

DWR has had difficulties staffing the California Energy Resources Scheduling Division (responsible for administering AB 1X):

- Recruiting and retaining employees was highly problematic.
- Used existing staff, hired additional staff, and retained experts under contract.

DWR spent a large amount on short-term energy supplies but expenditures have declined and will likely remain low. (Figures 13 and 14)

- January through August DWR spent $8 billion on short-term energy.
- Spent well over $1 billion per month from February through May.
- January through April market offers were insufficient so the DWR used out-of-market purchases to serve net-short.

Prices for short-term electricity began declining in June 2001 due to a combination of factors:

- Generator outages declined substantially.
- Natural gas prices decreased considerably.
- Demand declined significantly.
- New generation entered the market.
- Prices for No_X emission allowances declined.
- Reduced reliance on spot market purchases.
- FERC market mitigation order of June 2001.

Future Short-Term Expenditures Will Constitute Only a Fraction of Those for 2001 (Figure 17)

Spot market prices have declined significantly.

Fewer short-term purchases will be needed as deliveries from long-term contracts increase.

Net-short position will be smaller due to direct access increases.

DWR Has Resold Power Mostly To Balance Its Real-Time Transactions

First resale occurred in March and increased in July and August. (Figure 18)

High percentage of resales in August was in the real-time market.

Causes of real-time power sales appear to be result of several factors:

- Electricity demand and supply have routine variations.
- Inaccurate forecasts of demand and utility-retained generation.
- IOUs may be overestimating net-short position.

Division has not been able to assess causes of hourly imbalances because it does not have access to confidential market participant data (i.e., generator deviations, meter data, delivery path congestion).

Energy resales could increase substantially during next several years, particularly in Southern California during 4th quarter 2003 through 4th quarter 2005. Causes: Long-term contracts and declining net-short positions due to direct access.

More Systematic Analysis of Short-Term Transactions Is Needed

Net-short analysis will become more complex as dispatchable long-term contracts take effect.

- Long-term contracts for 2,900 megawatts of dispatchable energy will take effect in 2002.
- Flexibility will allow the DWR to take delivery of contract energy when spot market prices are higher and to purchase spot energy when it costs less.
- Meaningful portfolio management can reduce costs for consumers and its absence can unnecessarily increase costs.

Coordinated Dispatch of Utility Retained Generation Between the DWR and the Utilities Could Provide Savings

Minimize the cost of daily and hourly purchases by shaping schedule of hydro units.

Generate lower cost reserve using hydro units.

Reduce thermal unit production during periods of low energy market prices.

The utilities retail generation sales are tied directly to the amount of power they generate, meaning that reduced generation results in the utilities selling less energy.

THE FUTURE OF THE POWER-PURCHASING PROGRAM

Planning

A comprehensive strategic plan is needed for the power-purchasing program.

Strategic plan should consider these relevant factors:

- AB 1X, a short-term measure designed to address the immediate crisis must be replaced with a long-term strategic plan.
- The management of the existing long-term contracts cannot be easily transferred to other entities. ($42.6 billion contract portfolio)
- Key issues must be resolved: creditworthiness of IOUs, role of the Power Authority.
- Entity administering the program must have the ability to carry out the full functions of a program of this scale. (DWR is not yet well positioned to serve in this capacity.)
- If DWR is to continue to administer the program, it must improve its internal capabilities and operations.

Strategic plan should identify who will perform certain functions:

- It must consider the likelihood that the IOUs will not be able to purchase net-short.
- Whether to terminate DWR's role or transfer it to the Power Authority or to another entity.

Contract Management ($42.6 billion contract portfolio)

Contracts do not provide meaningful opportunities for the State to renegotiate or quit.

DWR has statutory right to petition FERC to void contracts to the extent rates are not "just and reasonable." However, in several contracts the DWR waives this right.

Even if the State fails to make payments under the contract, the decision to require performance (i.e. payment) versus to terminate the contract (and collect termination payments) is up to the seller.

Contracts offer little in the way of excuses for the State temporarily not performing. Excuse for not performing excludes adverse deviations in price as well as reduction in demand for power.

DWR can assign contracts to other governmental entities but assignment to IOUs requires sellers consent.

DWR should retain a "fresh set of legal eyes" to review contracts to help prioritize issues, strategize solutions, and then move ahead:

> **Example**: Williams contract has provision stating that if Williams incurs air emissions costs as a result of producing power for the DWR, the DWR must pay those costs. This exposes the DWR to $400 million to $688 million in potential costs over the life of the contract.

DWR needs to shield itself against potential events of default:

> **Example**: If the State repays the General Fund before it pays generators, the State's action could be an event of default resulting in termination of most contracts exposing the State to huge early termination payments.
>
> Many contracts contain provisions allowing the pass-through of certain costs (emissions credits, taxes, schedule imbalance penalties) from generators to the DWR. More than 15 large long-term contracts have clauses allowing the pass-through of governmental charges to the DWR.

Identify disadvantageous terms and use its strength to leverage a change in those terms.

Target contracts that are least desirable and have most dollar impact.

Opportunities for leverage include:

- Terms that establish performance minimums for generator.
- Terms that permit the DWR to monitor performance.
- Deadlines, such as commercial operation dates or other milestones.
- Items that require the DWR's consent.

DWR NEEDS TO IMPROVE ITS CAPABILITIES

Net-short Purchases

Continue to manage the net-short to reduce exposure to market risk in periods of high-demand and short supply. Net-short analysis will become more complex as dispatchable contracts take effect.

Servicing Agreements With IOUs

DWR must sell surplus power resulting from difference between estimated and actual customer usage.

DWR lacks processes to monitor IOUs performance in estimating customer needs. IOUs have no obligation to correct deviations.

DWR and IOUs have not agreed to sharing market data.

Servicing agreements provide auditing rights to the DWR and reporting responsibilities to the IOUs, but the DWR has not developed and implemented procedures or requirements for these.

Conflict of Interest

DWR needs to improve its efforts to prevent conflicts:

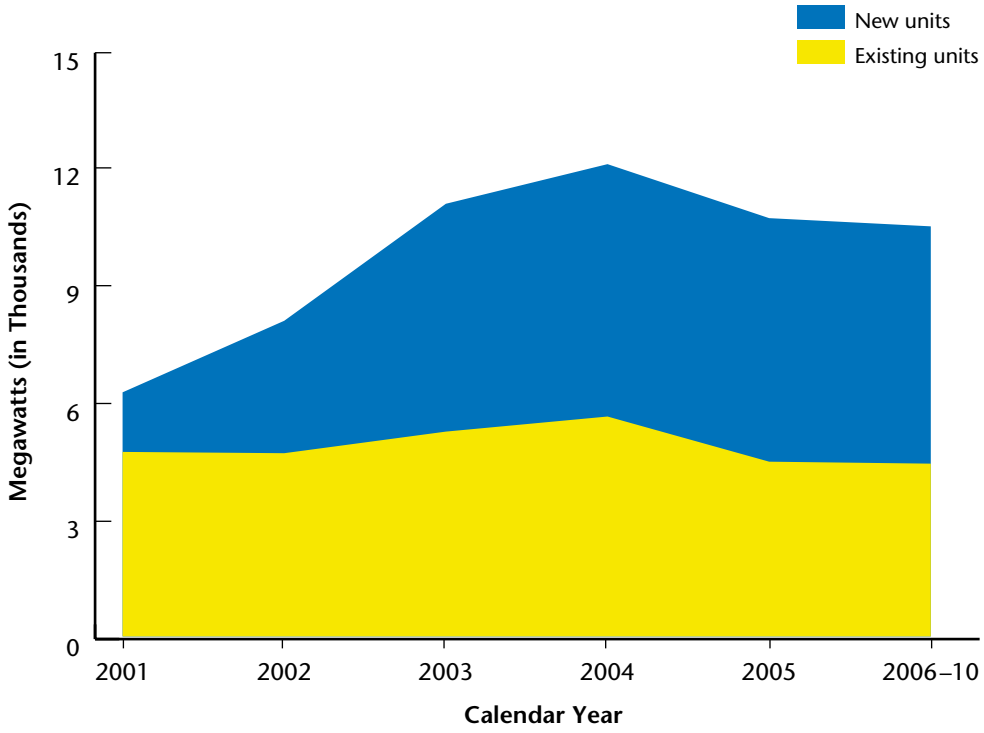
- We identified 15 individuals for whom DWR had no evidence of any effort to determine the need to file economic interest disclosure forms. In addition, an invoice for August 2001 listed 42 consultants, 22 were not in DWR's tracking system.

Internal Controls

DWR controls are not adequate to ensure all hours staff work are charged to the power-purchasing program. (14,300 staff hours not charged to the power-purchasing program)

FIGURE 1

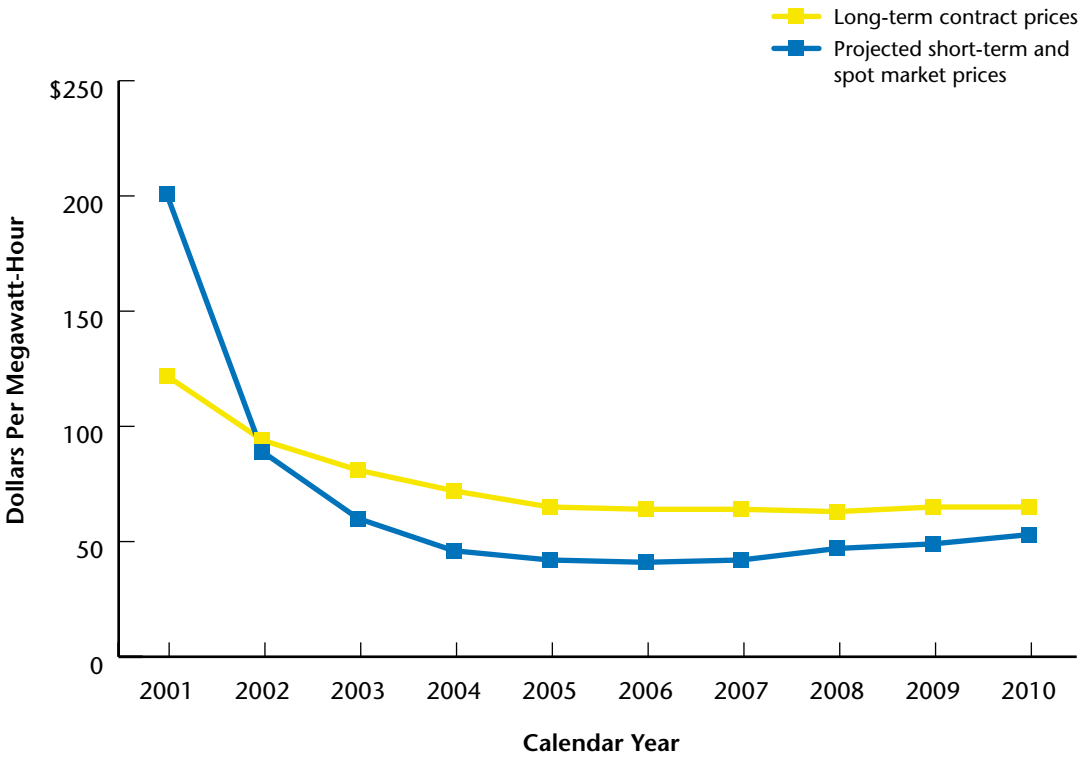
The Department of Water Resources' Contracts
New Units Versus Existing Capacity



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

FIGURE 2

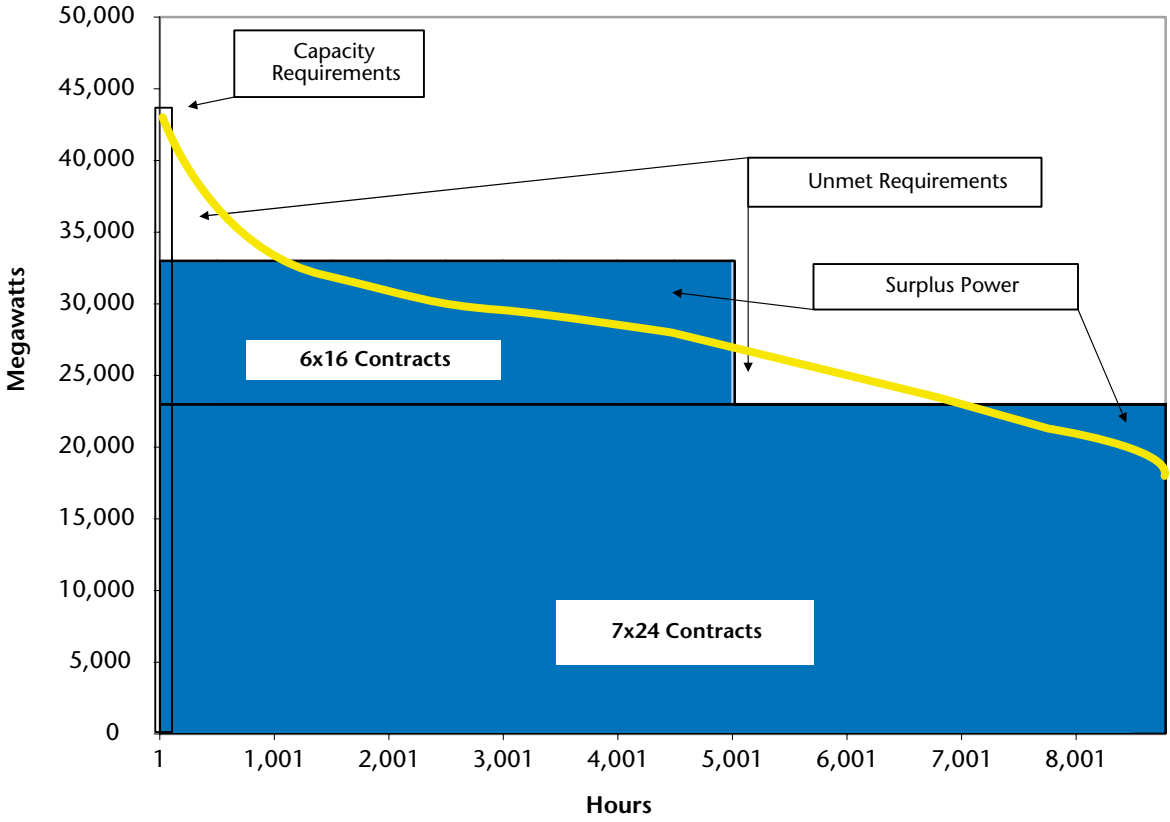
Projected Market Prices Are Lower Than the Department's Contract Prices (In Dollars per Megawatt-Hour)



Source: Data from Navigant Consulting, Inc., a Department of Water Resources consultant.

FIGURE 3

One Year's Representative Load Distribution by Hour



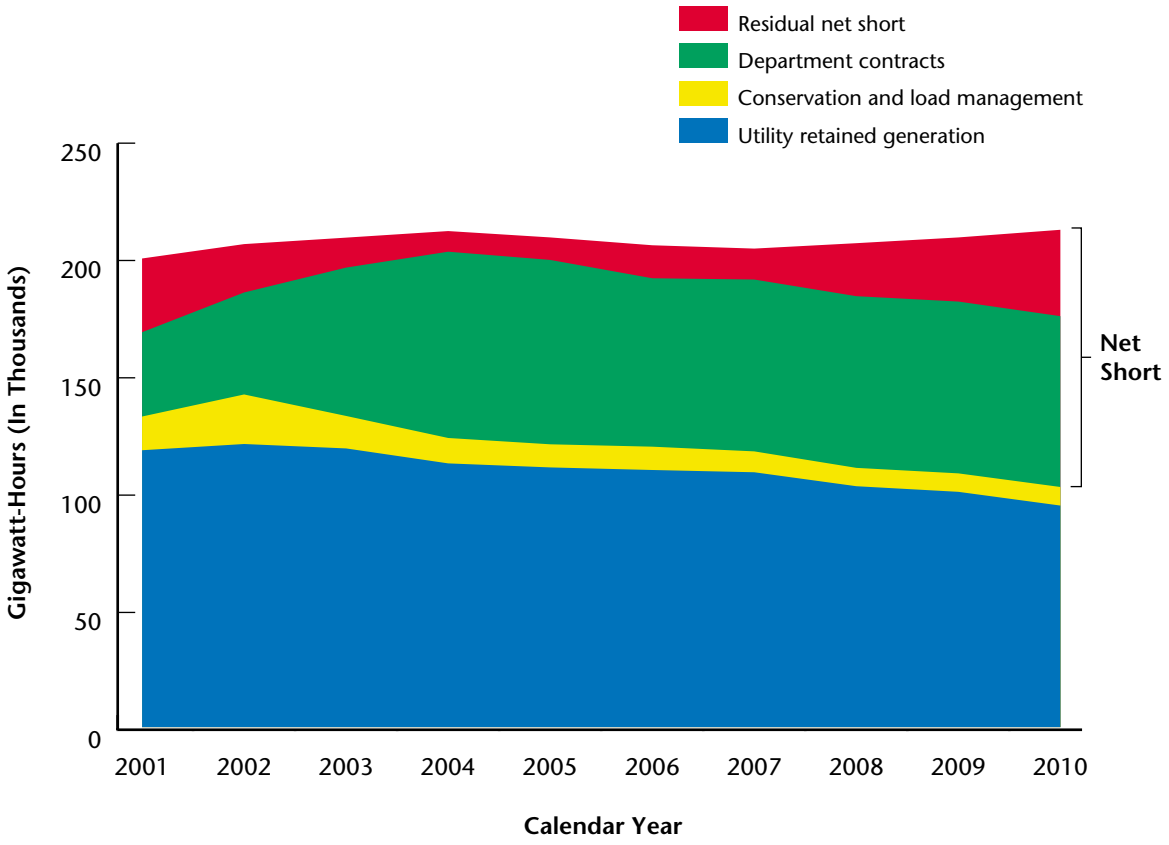
Footnotes:

The area under the line represents total electricity requirements, the shaded areas represent energy purchases, and the height of the column near hour 1 indicates the capacity requirement for the peak hour.

The purchase of 6x16 contracts involve agreements with sellers that produce energy 6 days a week, 16 hours per day. Similarly, the department has 7x24 contracts with sellers that generate energy 7 days a week, 24 hours per day.

FIGURE 4

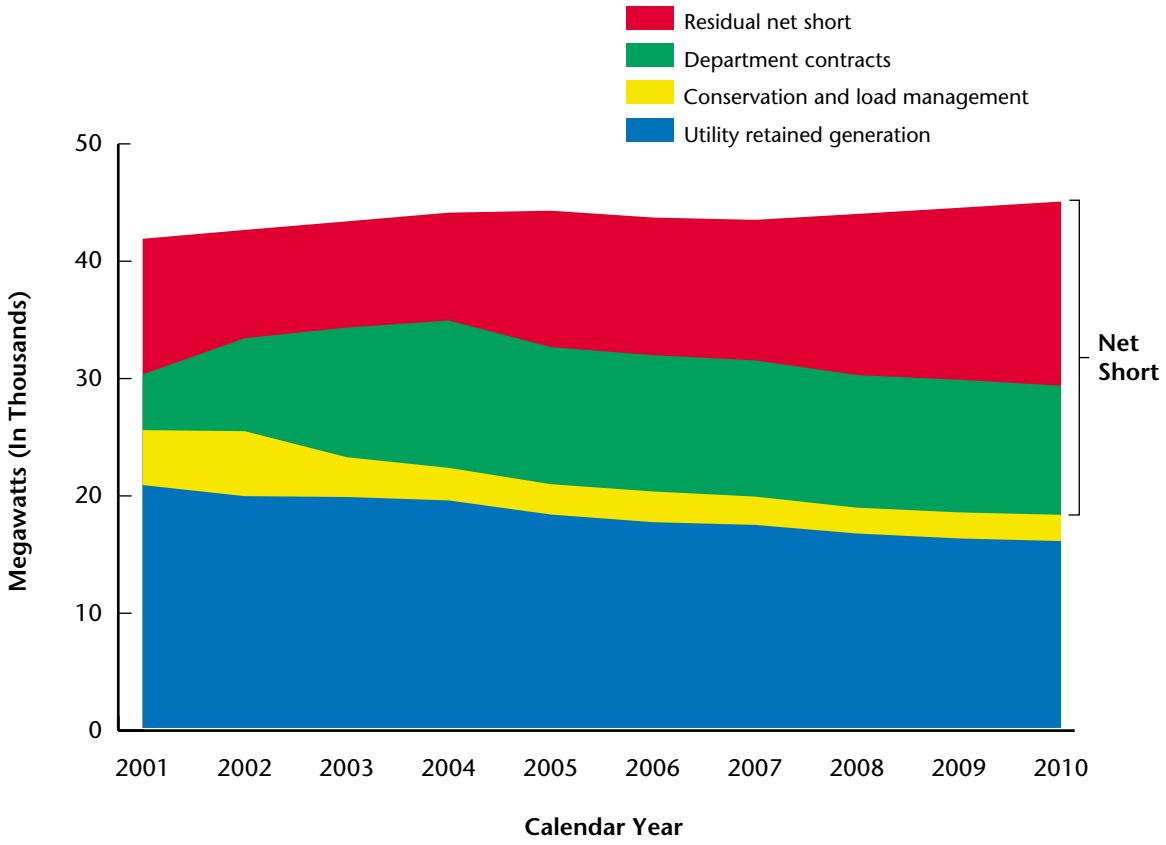
Forecasted Annual Net-Short Energy Position
2001 Through 2010



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

FIGURE 5

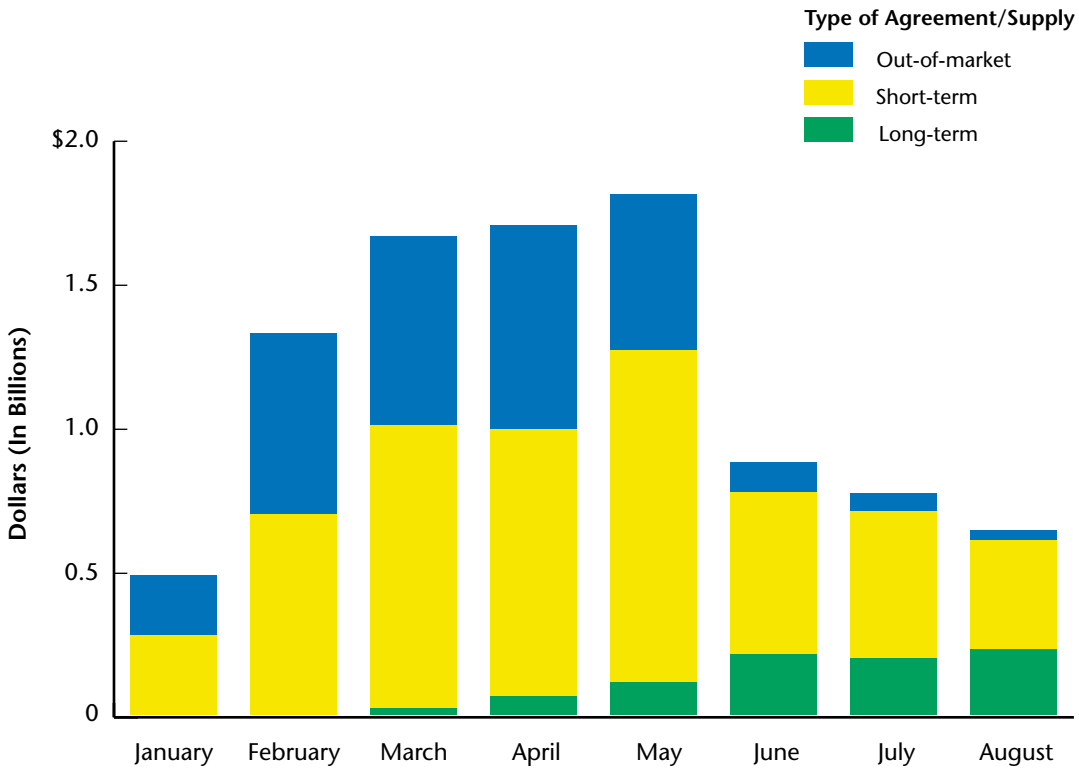
Forecasted Annual Net-Short Capacity
2001 Through 2010



Source: Analysis by LaCapra Associates using data from a July 25, 2001, draft report prepared by Navigant Consulting, a Department of Water Resources consultant.

FIGURE 13

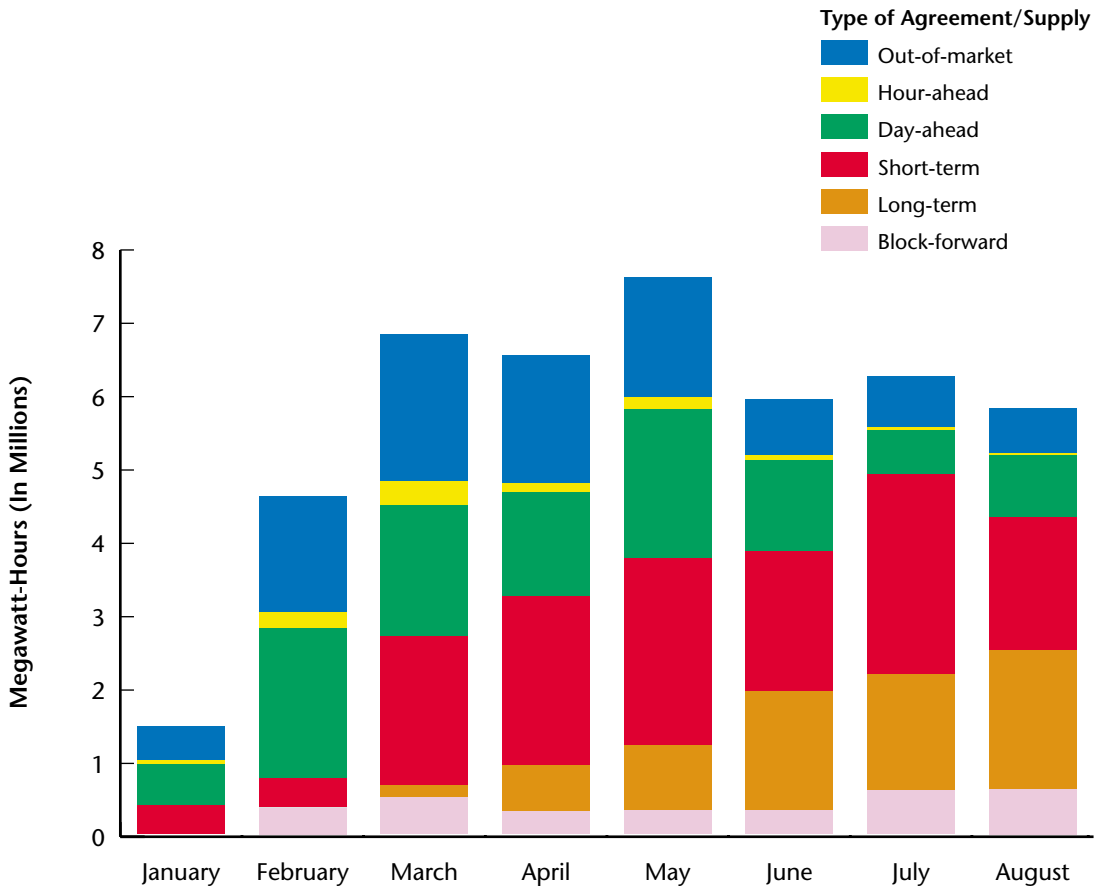
The Division's Gross Expenditures
January Through August 2001



Source: Data provided by the Department of Water Resources.

FIGURE 14

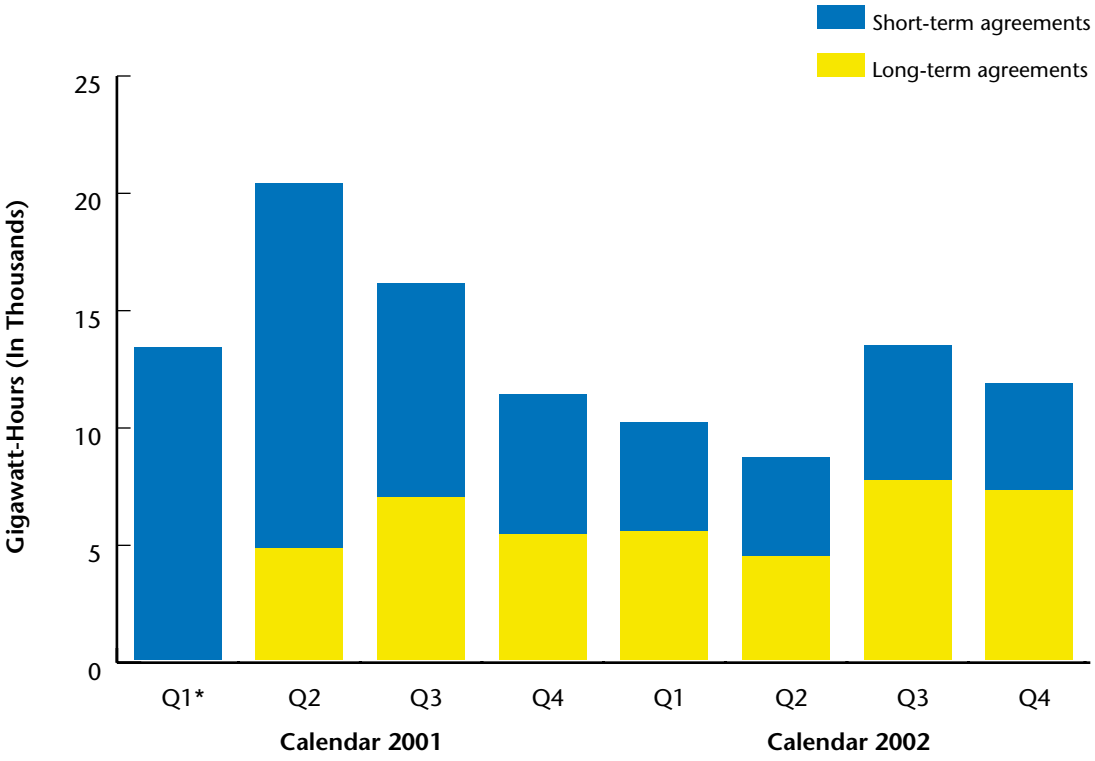
Total Division Energy Purchases
January Through August 2001



Source: Data provided by the Department of Water Resources.

FIGURE 16

The Division's Projected Purchases 2001 and 2002

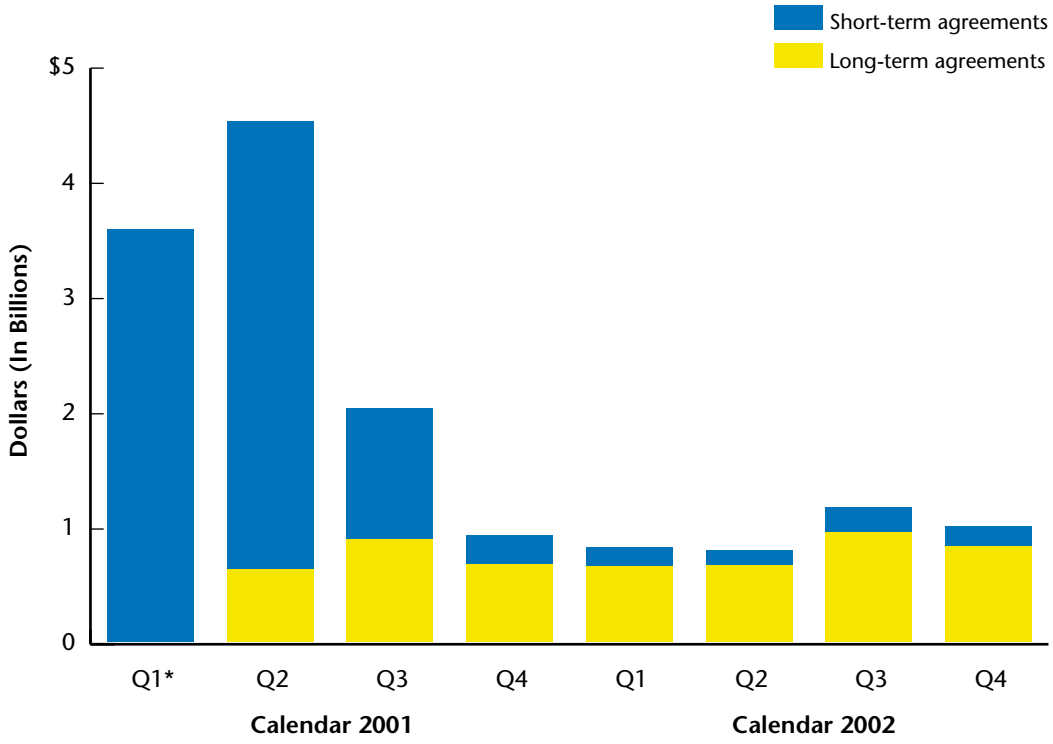


Source: The Department of Water Resources' November 5, 2001, Revenue Requirement Filing.

* Q = quarter

FIGURE 17

The Division's Projected Expenditures 2001 Through 2002

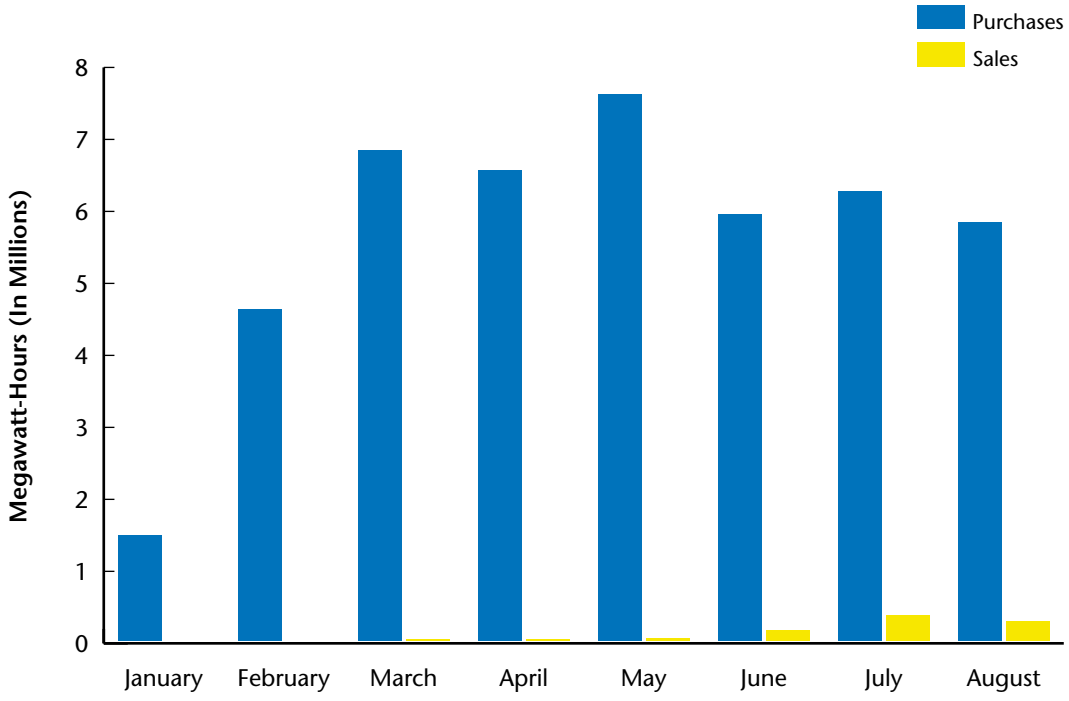


Source: The Department of Water Resources' November 5, 2001, Revenue Requirement Filing.

* Q = quarter

FIGURE 18

Division Energy Sales Compared to Purchases
January Through August 2001



Source: Data provided by the Department of Water Resources.

TABLE 8

Summary of Report Cards for Contracts Executed by the Department

Contracts Executed by March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
11	**Calpine**	7/1/01	10.5	Base	70,115	-3	-3	-3	-1	N/A	-2	0	-1
12	**Calpine**	8/1/01	20.0	Peak	7,958	-3	-3	-3	-1	N/A	-1	0	-1
13	**Calpine**	10/1/01	10.33	Base	64,596	-3	N/A	N/A	-1	N/A	-1	0	-1
6	**Dynegy**	3/6/01	0.83	Peak	4,094	-1	-2	N/A	-2	-1	-2	0	2
7	**Dynegy**	3/1/01	0.09	Off-peak	482	-1	-2	N/A	-2	-1	-2	0	2
14	**Dynegy**	1/1/02	3.0	Base	5,261	-1	N/A	N/A	-2	-1	-2	0	2
15	**Dynegy**	1/1/02	3.0	Peak	8,986	-1	N/A	N/A	-2	-1	-2	0	2
16	**Dynegy**	1/1/02	3.0	Peak	14,851	-1	-2	N/A	-2	-1	-2	0	2
17	**Dynegy**	1/1/02	3.0	Off-peak	1,747	-1	-2	N/A	-2	-1	-2	0	2
8	Williams	4/1/01	10.0	Peak	10,006	-2	1	N/A	-2	N/A	-3	0	0
9	Williams	6/1/01	4.5	Peak	4,578	-2	1	N/A	-2	N/A	-3	0	0
10	Williams	6/1/01	9.5	Base	21,983	-2	1	N/A	-2	N/A	-3	0	0
18	Williams	1/1/03	8.0	Peak	19,968	-2	1	N/A	-2	N/A	-3	0	0
		Total gigawatt-hours:			**234,625**								
		Average scores:				**-1.77**	**-1.00**	**-3.00**	**-1.77**	**-1.00**	**-2.15**	**0.00**	**0.69**

continued on next page

Agreement in Principle by March 2, 2001; Contract Executed After March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
19	High Desert	7/1/03	8.25	Base	51,896	-2	-3	2	1	N/A	-2	2	0
20	Constellation	4/1/01	2.25	Peak	2,246	-1	N/A	N/A	1	N/A	-2	2	2
27	**Allegheny**	1/1/03	1.0	Peak	749	-1	N/A	N/A	1	N/A	-2	0	2
21	**Allegheny**	3/23/01	0.58	Peak	1,270	-1	-1	N/A	1	N/A	-2	0	2
22	**Allegheny**	10/1/01	10.25	Base	61,880	-1	-1	N/A	1	N/A	-2	0	2
28	**Sempra**	6/1/01	10.3	Peak	22,339	-2	-2	-3	0	1	-1	0	2
29	**Sempra**	4/1/02	9.5	Base	70,986	-2	-2	-3	0	1	-1	0	2
43	Cal Peak (ii)	10/15/01	10.0	Super Summer Peak	2,154	2	3	2	0	2	2	1	0
44	Cal Peak (ii)	10/15/01	10.0	Super Summer Peak	2,873	2	3	2	0	2	2	1	0
45	Cal Peak (ii)	11/1/01	10.0	Peak	0	2	3	2	0	2	2	1	0
	Cal Peak (ii)	11/1/01	10.0	Peak	0	2	3	2	0	2	2	1	0
40	Sunrise	8/1/01	1.42	Super Summer Peak	447	3	2	1	0	1	0	2	0
41	Sunrise	3/1/03	8.58	Base	38,441	3	2	1	0	1	0	2	0
		Total gigawatt-hours:			**255,281**								
		Average scores:				**0.31**	**0.64**	**0.67**	**0.38**	**1.50**	**-0.31**	**0.92**	**0.92**

Both Agreement in Principle and Actual Agreement Executed After March 2, 2001

						Reliability			Price Risk		Flexibility to Renegotiate		Assignment
Contract Number	Supplier	Start Date	Term (Years)	Product (i)	Ten-Year Energy Purchases (Gigawatt-Hours)	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	
31	GWF	9/1/01	11.33	Summer Peak	23,713	3	3	1	-2	2	2	0	0
32	Mirant	6/1/01	1.5	Peak	3,952	-3	N/A	N/A	1	N/A	-1	0	0
33	**Coral**	5/24/01	11.25	Peak	13,520	1	4	3	1	1	2	0	0
34	**Coral**	7/1/03	11.25	Peak	5,049	1	4	3	1	1	2	0	0
35	**Coral**	7/1/02	10.0	Base	5,729	1	4	3	1	1	2	0	0
36	**Coral**	7/1/04	10.0	Peak	4,378	1	4	3	1	1	2	0	0
39	Pacificorp	7/1/01	10.0	Base	21,900	3	3	N/A	0	1	1	1	2
48	**Calpine SJ**	5/1/02	3.0	Peak	3,024	1	2	0	1	1	2	0	-1
			Total gigawatt-hours:		**81,265**								
			Average scores:			**1.00**	**3.43**	**2.17**	**0.50**	**1.14**	**1.50**	**0.13**	**0.13**

Grade summary

Average scores per period:	Delivery	Availability	New Generation	Uncertainty	Tolling	Constraints	Government Relief	Assignment
Contract by March 2	**-1.77**	**-1.00**	**-3.00**	**-1.77**	**-1.00**	**-2.15**	**0.00**	**0.69**
Agreement in principle by March 2	**0.31**	**0.64**	**0.67**	**0.38**	**1.50**	**-0.31**	**0.92**	**0.92**
Contract or agreement in principle after March 2	**1.00**	**3.43**	**2.17**	**0.50**	**1.14**	**1.50**	**0.13**	**0.13**

Notes:

The grades shown here correspond to the overall grade for each category shown in Appendix C. Refer to Table 11 in Appendix C for the more detailed ratings of each contract.

N/A Attribute is not applicable.

(i) The product codes are explained in Appendix A.

(ii) Because the department separates the power from the Cal Peak contracts between parts of the year, it treats Cal Peak as four contracts. We show all four contracts here since our consultant evaluated the legal terms of each contract individually. Elsewhere in the report, we treat the transactions as two contracts.

Supplier names in bold indicate that they were reviewed in detail by our consultant.